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Other Criteria Affecting SAGD Performance in the Athabasca McMurray Formation

Alberta
ENERGY

April 1997

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Other Criteria Affecting SAGD Performance in the Athabasca McMurray Formation

A companion to a report "Possible Effects of Gas Caps on SAGD Performance"

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April 1997

Contents

1.0 Executive Summary 1

Overburden Thickness 1

Net Pay Thickness 1

Water Sands 1

Sensitivities 2

2.0 Introduction & Background 6

3.0 Effect of Overburden Thickness 6

3.1 Geology 6

3.2 Well Pair Performance Predictions 6

3.3 Commercial Project 7

3.4 Social Supply Cost 7

3.5 Summary and Findings 8

4.0 Effect of Net Pay Thickness 15

4.1 Model Description 15

4.2 Simulation Results 15

4.3 Commercial Projects 15

4.4 Social Supply Cost 15

4.5 Summary and Findings 15

5.0 Effect of Overlying Water 21

5.1 Model Description 21

5.2 Simulation Results 21

5.3 Commercial Project 22

5.4 Social Supply Costs 22

5.5 Summary and Findings 22

6.0 Sensitivities 34

6.1 Pattern Life 34

6.2 Gas Price 34

6.3 Discount Factor 34

6.4 Other Reservoir Parameters 34

Appendix 1 43

Overburden Considerations, Simulation Data Set and Results, Commercial Plant Utilization and Detailed Plant Bitumen Forecasts and Undiscounted Costs for Athabasca McMurray

Appendix 2 57

Pay Thickness Simulation Data Set and Results, Commercial Plant Utilization, Detailed Plant Bitumen Forecast, and Undiscounted Cost for Athabasca McMurray

Appendix 3 68

Overlying Water Effect Data Set and Results, Commercial Plant Utilization and Detailed Plant Bitumen Forecasts, and Undiscounted Costs for Athabasca McMurray

Appendix 4 114

Extending the SAGD Process to Other Reservoir Types — Sensitivity Study

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1.0 Executive Summary

In November 1995 staff from the Alberta Department of Energy and the Alberta Energy and Utilities Board initiated a series of numerical modelling studies to assess the applicability of the steam assisted gravity drainage (SAGD) bitumen recovery process under a variety of reservoir conditions. These included overburden net pay thickness, overlying gas and water sands and other general reservoir quality issues.

This report, to be used as a companion to one entitled **Possible Effects of Gas Caps on SAGD Performance** dated March 1997 which addressed gas cap effects in the Athabasca McMurray oil sands and the Cold Lake Clearwater oil sands at Wolf Lake and Burnt Lake, summarizes assessments of the other criteria: overburden thickness, net pay thickness, the effect of overlying water sands by themselves and in combination with gas caps on the SAGD recovery process as well as sensitivities of other reservoir qualities. Because this is a companion report; the introduction, background and methodology in the main report are not repeated in this report.

Overburden Thickness

Overburden thickness is one of the concerns for bitumen producers in Athabasca McMurray oil sand. Mining becomes less attractive as overburden thickness increases relative to the recoverable bitumen volume. In-situ steam recovery processes are more attractive with greater overburden thicknesses as this enables the process to operate at greater pressures and correspondingly higher temperature and bitumen production rates. The SAGD process is quite gentle. Using gravity as the driving force the SAGD process does not require a high pressure differential in the reservoir to displace fluid to the production wells and can be operated at relatively low reservoir pressures. Although steam at lower pressures is more efficient because of a greater portion of usable (latent) heat and lower losses to the over and underburden, the associated lower temperatures create less reduction in bitumen viscosity and lower bitumen production rates than at higher pressures.

Steam injection and bitumen and water production rates were predicted by numerical models for typical 500m long SAGD well pairs in oil sand with a net pay of 24m, similar to the UTF at three overburden thicknesses, 50m, 100m and 140m. Social supply costs were calculated for 30,000 barrels of bitumen per day, commercial projects having 30 year lives. Based on steam chamber operating pressures equivalent to the fluid gradient corresponding to the overburden thicknesses it was found as expected that both CDOR and CSOR decreased with decreasing overburden. Figure 1.1 illustrates the bitumen recovery and social supply cost for the three overburden thicknesses studied. Although the CSOR decreases with reduced overburden thickness which would reduce steam costs, the lower production rates increased the number of wells required initially and well costs. As a result the discounted social supply cost increased from \$8.78/bbl at 140m overburden to \$10.13/bbl at 50m overburden. Bitumen recovery shows a slight decrease with reduced overburden thickness as expected due to lower production rate and economic limit effects. At this time, it appears that SAGD is viable at overburden thicknesses as low as 50m to 60m. Applications in different quality and thickness of oil sand, however, will have different performance in relation to overburden thickness.

Net Pay Thickness

Net pay thickness effects were assessed to determine the minimum net pay necessary for SAGD to be viable in the Athabasca McMurray oil sand. Four net pays, proportionally similar in reservoir properties to the McMurray oil sand at UTF, at 140m overburden, were studied. Steam injection and bitumen and water production rates were predicted by numerical models for typical 500m long SAGD well pairs operated at 1400 kPa steam chamber pressure. Social supply costs were then calculated for 30,000 barrels of bitumen per day, commercial projects operated for 30 years. Since bitumen production rates in SAGD projects are a function of net pay and heat loss per unit of bitumen resource is greater for thinner pay sections, CDORs decrease and CSORs increase as net pay decreases. As summarized on Figure 1.1, social supply cost increases gradually from \$7.35/bbl to \$9.35/bbl of bitumen as net pay decreases from 45m to 16m then increases abruptly to more than \$15/bbl for 8m of net pay. Bitumen recovery shows similar behaviour declining gradually from 82% to 74% as net pay decreases from 45m to 16m then decreases abruptly to 41% at 8m of net pay.

The significant trend change in social supply cost between 16m and 8m net pay is due to well drilling and steam costs resulting from a chain of effects initiated by relatively low CDOR for 8m net pay. The low CDOR causes disproportionately low bitumen recovery per well pair, which necessitates a larger number of wells to fill a commercial plant for 30 years. These wells cover larger areas in which disproportionate heat losses to the overburden occur. The assessment indicates that, for the quality of oil sand used in the study, the minimum thickness needed for SAGD to be viable is in the order of 15m. This minimum thickness will however, vary with quality of oil sand, overburden thicknesses, and bitumen price.

Water Sands

The main report focussed on the effect of gas caps, both non-depleted and depleted, on SAGD performance. Gas caps in the Athabasca McMurray however are quite often associated with water sands which underlie the gas and overlay the bitumen. These water sands can also be present without gas caps. Preliminary effects of these water sands, with and without gas caps, were studied and compared to gas cap effects previously presented.

As in previous assessments, steam injection and bitumen and water production rates were numerically simulated for 500m long SAGD well pairs operated with steam chamber pressures of 2600 kPa and steam injection rate limits of 400 m^3/d for non-depleted and depleted overlying gas and/or water zones of various thicknesses. Social supply costs were then calculated for 30,000 barrels per day, commercial projects operated for 30 years.

In general, as in the gas cap study, thicker overlying gas/water zones reduce bitumen recovery and increase CSOR and social supply costs. Figure 1.2 shows social supply cost and bitumen recovery comparisons for various thicknesses of gas and water sands. With exception of the non-depleted 10m gas cap, in which the outflow of fluid through the gas cap well was restricted giving better performance, water sands appear based on numerical simulation to have slightly less negative impact on social supply costs than gas caps. Bitumen recovery decreases with increasing gas cap and water sands thickness and is generally less for depleted as compared to non-depleted pressures. With the exception of the 5m water sand and gas cap cases, bitumen recovery is also better with the water sands than gas caps. Movement of bitumen into the overlying water and gas sands is simulated to occur. The volume of this bitumen seems to be generally proportional to the amount of outflow from the pattern due to thickness of the overlying sands and pressure differential between the steam chamber and the overlying sands and may explain the social supply cost and bitumen recovery differences. As with gas caps, however, the reservoir mechanisms of steam moving into water sands are very complex and not well understood at this time. Until laboratory and field test results are available to validate the predictions obtained by simulators, the results must be used cautiously.

Sensitivities

Sensitivities of SAGD performance to a gas price, pattern life, discount rate and certain reservoir properties were studied and are summarized using spider diagrams on Figure 1.3(a) and (b). Social supply cost sensitivities based on the Athabasca 10m depleted gas cap case were investigated for gas price, pattern life and discount rate.

Gas Price

– Reducing gas price by 25% from $2.20/GJ, used in the study has a significant effect reducing the social supply cost by about 8%. Bitumen recovery is only modestly increased. Increasing gas price by 25% increases supply cost by 3.5%, however, bitumen recovery is significantly reduced from 63% to 26% due to a much higher well pair economic production rate limit.

Pattern Life

– The lengths of time that well patterns are operated might be a commercial project consideration in determining the best use for steam and facilities. Pattern life was varied from four to 10 years showing that social supply cost for the base 8-year life did not change significantly with a 25% reduction. Slight increases at 50% reduction and 25% increases are expected due to less recovery and uneconomic steam use respectively.

Discount Rate

– Social supply costs are essentially the bitumen price at which a rate of return before royalty and taxes equal to the discount rate will be achieved. As expected, increasing the discount rate significantly increases social supply price. Although 10% discount was assumed in the study, a 15% discount rate was used as a base in Figure 1.3(a). A 33% increase and decrease in a discount rate to 20% and 10% yielded changes to social supply cost of 18.4% and 16.5% respectively.

Sensitivities of a number of reservoir parameters on SAGD process performance were studied by ADOE (formerly AOSTRA) in 1992. Although commercial project social supply costs were not determined in that study, the effects of certain reservoir parameters on a cumulative steam oil ratio (an indication of social supply cost) were interpolated from the study and are shown on Figure 1.3(b).

Net Pay

– A 25% increase from the 20m base case net pay results in 5% decrease in CSOR. This effect, caused by decreasing the portion of heat lost to over and underburdens relative to total heat injected is small but will increase considerably as the base net pay thickness decreases.

Bitumen Saturation

– A 25% decrease from the 85% base case bitumen saturation results in a significant 41% increase in CSOR. Not only is the bitumen volume available for recovery less at reduced bitumen saturation but more water must be heated.

Horizontal and Vertical Permeability

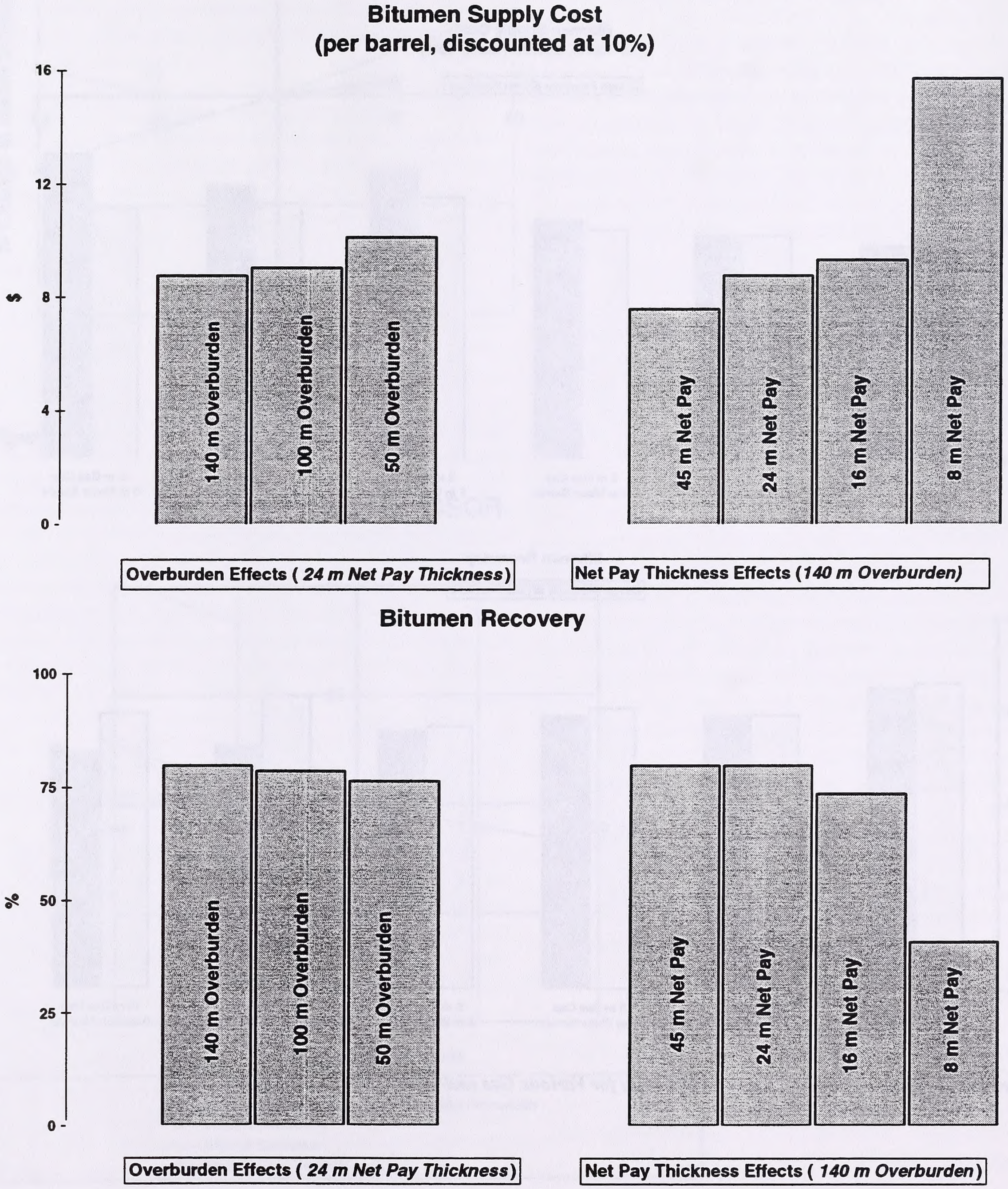
– A 25% reduction from the base case 10 D and 5 D permeabilities respectively results in a modest increase of 3.6% in CSOR. Although not investigated in this study reducing permeabilities to much lower values, to in the order of 1 Darcy would significantly effect results.

Vertical Permeability

- A 25% decrease from the 5 D base case vertical permeability results in a small increase in CSOR of 2.2%. The same comments as made for the combined horizontal and vertical permeability, however, apply to vertical permeability.

Initial Bitumen Viscosity

- A 25% decrease from the 1,000,000 cp base case viscosities had very little effect on CSOR. Bitumen viscosities which are reduced very significantly with heating are more comparable at steam temperatures than at initial reservoir temperatures.



Bitumen Supply Cost (per barrel, discounted at 10%)

Bitumen Recovery

Figure 1.1 — Bitumen Supply Cost and Recovery for Various Overburden and Net Pay Thicknesses

Some additional findings of the 1992 study were that SAGD performance was improved in lower permeability sands if the separation between injection and production wells was increased, and non-permeable tight streaks of limited areal extent and bottom water had little effect on the process. Better performance was also observed in a layered permeability reservoir when the higher permeability was located below the lower permeability and both the injection and production wells are located in the higher permeability layer.

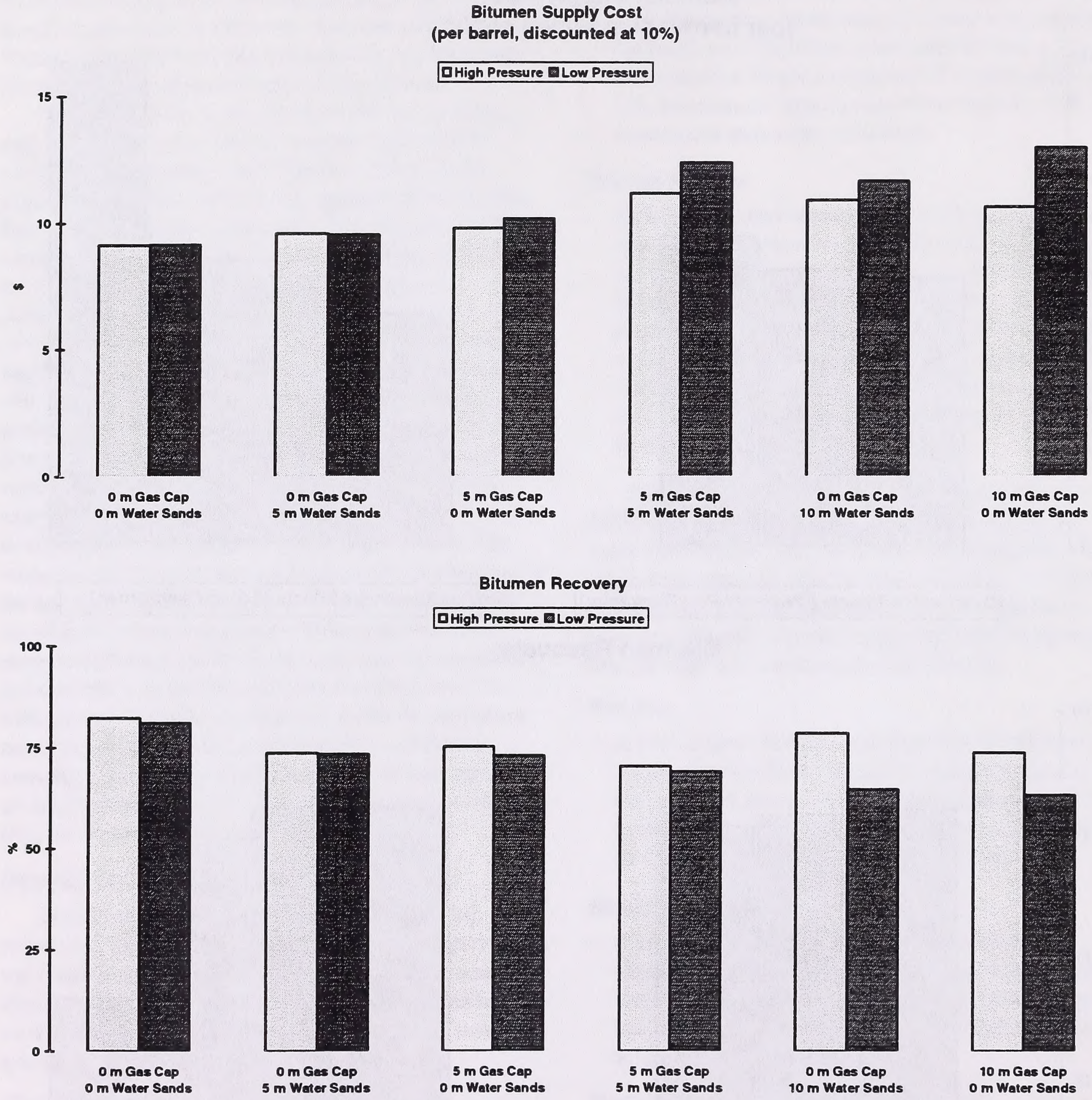


Figure 1.2 — Bitumen Supply Costs and Recovery for Various Gas and/or Water Sand Thicknesses

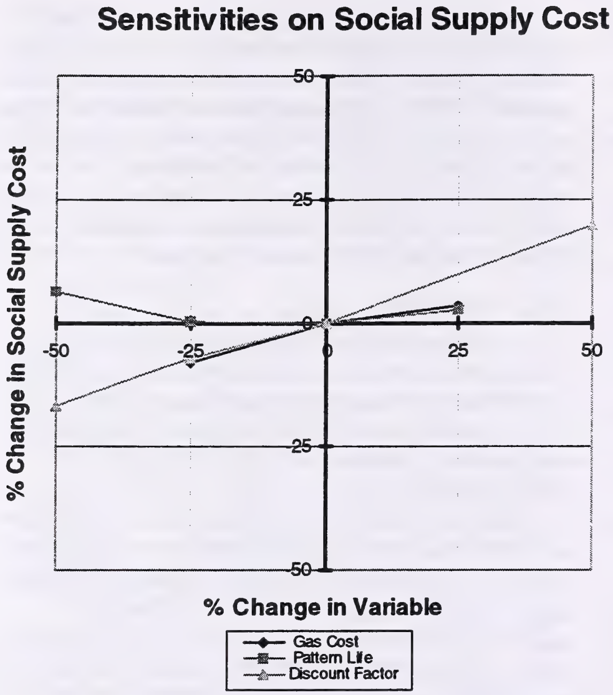


Figure 1.3(a)

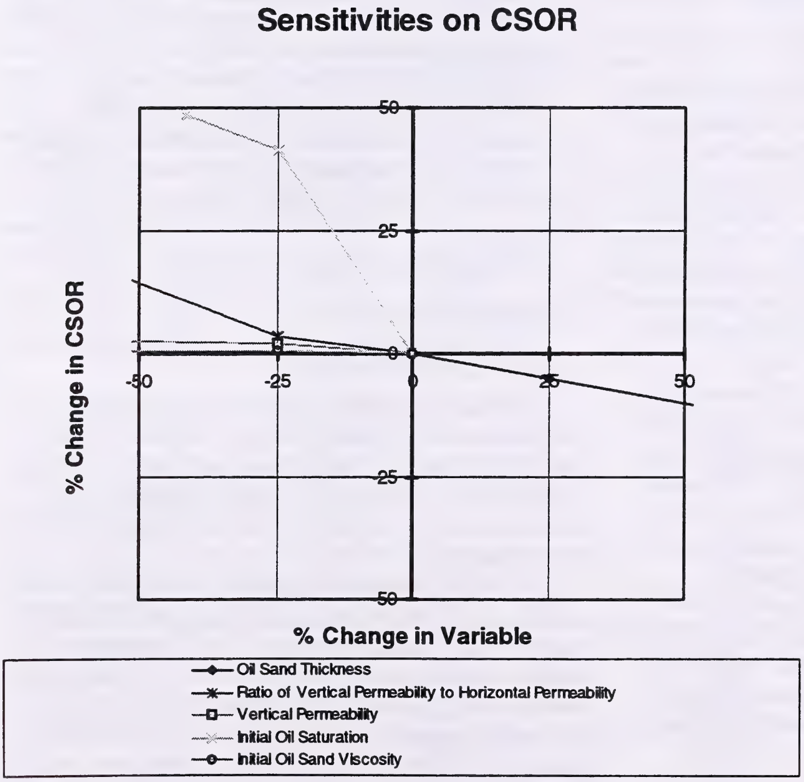


Figure 1.3(b)

2.0 Introduction & Background

This is a companion to a report entitled "Possible Effects of Gas Caps on the SAGD Performance" dated March 1997. Much of the introduction, background and methodology applicable in this report are contained in that report and are not repeated.

The possible effects of overburden, pay thickness, overlying water sands and other sensitivities on SAGD performance in the Athabasca McMurray Formation are summarized in this report. The objective for the Alberta Energy and Utilities Board and the Alberta Department of Energy was to assess, on a preliminary basis, the potential of the SAGD recovery process in different reservoir environments and of investigating reservoir factors which may influence its performance.

Individual well pair CDORs (calendar day oil rates), CSORs (cumulative steam oil ratios) and bitumen recoveries were obtained from numerical simulation studies. Social supply costs were estimated based for commercial plant forecasts for each scenario to provide comparative assessments.

3.0 Effect of Overburden Thickness

The minimum depth at which the SAGD process can be applied is of concern in Athabasca where the oil sand is shallow and outcrops along rivers in the deposit. Recovery process alternatives are being considered by Industry particularly as leases come up for renewal. The purpose of this component of the study is to investigate the relationship between a reservoir's overburden depth and the SAGD process social supply cost and recovery and to determine a reasonable minimum overburden at which SAGD might be applied.

A number of studies conducted by ADOE in conjunction with Industry partners have addressed the commercial potential of the process at reduced overburden thicknesses. This study presents a generic comparison of SAGD performance at several overburden thicknesses and does not consider unique synergisms which may be available in an area with both surface mining and in-situ operations.

The most important characteristic influencing SAGD performance from an overburden thickness standpoint is the steam chamber operating pressure. The pressure should be high enough to provide adequate bitumen productivity without losing steam vertically to the surface or horizontally to nearby out crops.

Overburden considerations influencing the relationship of SAGD operating pressure to overburden thickness for the Athabasca Wabishaw-McMurray formation are addressed in Appendix 1. Although operating pressures close to fracture pressure may be possible for very rich oil sand with competent overburden, for the purposes of this study, a conservative approach limiting the operating pressure of the SAGD process to the hydraulic head equivalent to the thickness of the overburden has been adopted.

3.1 Geology

The geology for the Athabasca Wabishaw-McMurray formation is quite variable and specific to site when predicting performance of the SAGD process. The cap rock and bitumen saturation in the reservoir are particularly important when considering the effect of overburden thickness on SAGD application.

If the overburden is too thin, of poor cap rock quality, or has been breached by core holes not effectively abandoned, there exists the possibility of steam breaking through to the surface if the operating pressure is too high. If bitumen saturation in some of the oil sand is low allowing water mobility, the injected fluid may leak off laterally. Figure 3.1 shows a map of overburden thicknesses in the Athabasca mining area. The areas of overburden in the ranges of 0-50m, 50m-75m and 75m-100m are approximately 212,000 ha, 62,000 ha and 20,000 ha, respectively in the 313,000 ha area considered being surface minable. Areas having greater overburden than 50m may not be economically mined.

The reservoir properties used to simulate SAGD performance for various overburden thicknesses were those for the UTF site and previously described in section 5.1 of the base report, "Possible Effects of Gas Caps on SAGD Performance."

3.2 Well Pair Performance Predictions

3.2.1 Model Description

The multi well model used to study gas cap effects was not used for this overburden study. Instead a simpler single well pair 2D model was thought to be adequate for studying the effects of overburden in the Wabishaw-McMurray oil sand. The reservoir rock and fluid saturation data description is listed on Table 3.1.

The "short circuit layer" previously incorporated in the model used to study the gas cap effects was removed for the purpose of simulating overburden effects. The absence of the short circuit layer may give rise to slightly lower production rates than predicted by the 3D model previously used. The results, however, will be consistent between cases and conclusions based on the reservoir description used should be valid.

The 2D reservoir model is 24m thick, is stratified with porosity of 30% and 35% and has horizontal and vertical permeability ranges of 2 to 10 darcies and 0.2 to 2.5 darcies respectively. The oil saturations are 75% and 85% and the well pair separation is 4.5m with 90m inter-well spacing between well pairs. The grid block dimensioning is 30 blocks each, 1.5 metres in the i-direction (horizontal perpendicular to the well pairs), 1 block, 500 metres in the j-direction (horizontal parallel to the well pairs), and 16 blocks each 1.5 metres in the k-direction (vertical).

The steam chamber operating pressure is assumed to be the hydrostatic head for the overburden thickness in question, that is, 1400 kPa, 1000 kPa and 500 kPa for overburdens of 140m, 100m and 50m respectively.

3.2.2 Simulation Results

The following summarizes the results of simulations for various overburden thicknesses. Plots of the bitumen and water production and steam injection on a well pair basis for each case are also shown on Figures 3.2 to 3.4

As anticipated the CDORs (calendar day oil rates), decreased from 68 m^3/day with 140m overburden to 34.3 m^3/day with 50m overburden due to the lower operating pressures and temperatures and resulting less reduction in viscosity with thinner overburden. Bitumen recovery at reduced overburden depths is also slightly lower ranging from 79.8% to 76.4% also due to the economic limit being reached earlier in lower CDOR cases. The change in recovery however is not proportional to the change in CDOR and as a result, wells with lower overburden thickness have significantly longer economic production lives. The CSOR (cumulative steam oil ratio) also decreases with decreasing overburden thickness due to improved steam efficiency resulting from fewer heat losses to the over and underburden at lower temperatures and more useful (latent) heat at lower pressures.

The data sets and detailed plot of simulation results as well as more related information are included in Appendix 1.

3.3 Commercial Project

The well pair performance plots from the simulation runs were used to generate well pair drilling schedules and commercial project bitumen and water production and steam injection predictions as shown on Figures 3.5 to 3.7.

The well pairs necessary to supply a 30,000 barrels per day plant for 30 years was 218, 218 and 226 for cases 1, 2 and 3 respectively. Cases 1 and 2 have the same number of well pairs. One would expect to have needed more wells in case 2, however, due to a combination of factors such as differences in well production profile shape, criteria for adding wells and ultimate recovery, this was not the case. In case 2 (100m overburden) four additional well pairs were added in each of the first three years in order to fill the commercial plant. These 12 wells were not added in years 20 and 21 whereas 12 wells were added in those years in case 1 (140m overburden).

3.4 Social Supply Cost

The costs of drilling and completing horizontal wells at shallow depths and for low pressure steam operations are not demonstrated at this time. A previous study of applying SAGD at a location with 30 to 40 metres of overburden concluded that a river crossing style drilling rig would have to be modified to drill at a spudding angle of 32° from horizontal. The lower steam operating pressure would create higher pressure drops in tubulars than currently experienced, however rates would be lower which would compensate to some extent for the effect of the lower pressure. It has been assumed for this study that the drilling and completion costs would be the same as for deeper locations.

Social supply costs for the three overburden cases range from a low of $8.78/bbl for the 140m overburden case to $10.13/bbl for the 50m overburden case and are shown, including a breakdown into cost centers, on Table 3.2. Although the gas cost for steam is less, due to lower CSOR, this was more than offset by additional well drilling costs (timing and number of well pairs) resulting in higher social supply costs for thinner overburdens.

Property	Case 1 140m overburden	Case 2 100m overburden	Case 3 50m overburden
Steam Injection Press. (kPa) (95% quality)	1400	1000	500
Steam Injection Temp. (°C)	194.8	179.7	151.7
Pattern Life (yrs)	8.75	10.75	16.75
Oil Production (m^3)	219,011	215,639	209,682
CDOR (m^3/day)	68.5	54.9	34.3
Steam Injection (m^3)	502,407	470,507	441,182
CSOR	2.29	2.18	2.10
Recovery (%OOIP)	79.8	78.6	76.4

3.5 Summary and Findings

A brief commercial plant production and supply cost summary for each overburden thickness is tabulated below:

	Case 1	Case 2	Case 3
Overburden Depth (m)	140	100	50
Pattern Life (yrs)	8.75	10.75	16.75
Supply Cost ($/Bbl)	8.78	9.07	10.13
Plant Production (E^6m^3)	47.1	45.3	44.0
Plant Utilization (%)	90.2	86.7	84.3
Total Wells	218	218	226

CDOR and CSOR for each overburden thickness from numerical simulations are plotted on Figure 3.8 and show that both bitumen production rates and steam oil ratios for individual well pairs decrease with decreased overburden thickness. Lower steam chamber pressures assumed necessarily for thinner overburdens reduce the steam chamber temperature. This reduced temperature causes less reduction in bitumen viscosity and therefore lower bitumen production rates. A lower temperature, however, has the advantage of providing higher steam efficiency (more of the heat is in the latent or usable form) and less heat loss due to lower temperature difference between the steam chamber and over and underburden. Both of these factors contribute to a lower CSOR in thinner overburdens.

Bitumen recovery and social supply costs are shown for various overburden thicknesses on Figure 3.9. Bitumen recovery varies from 79.8% at an overburden of 140m down slightly to 76.4% at an overburden of 50m. The social supply cost over the same overburden range varies from $8.78/bbl to $10.13/bbl suggesting that the SAGD process is viable at overburdens of 50m or thicker. Although steam costs are lower with thinner overburden, shallower reservoirs operated at lower pressures have lower peak production rates generally requiring more well pairs drilled earlier. These factors increase well costs and more than offset reduced steam cost. The effect of well drilling timing is illustrated by comparing social supply costs for cases 1 (140m overburden) and 2 (100m overburden) which each use 218 well pairs. In case 2, 12 additional well pairs are drilled in 1997 to 1999 than in case 1 but case 1 has 12 additional well pairs drilled in 2017 and 2018. Although the 1995 costs are the same, discounting yields total drilling costs of $1.97/bbl for case 1 and $2.23/bbl for case 2.

SAGD performance depends upon a number of factors not addressed in this assessment and results should be considered only as a general guideline. Although net pay, qualities of pay and overburden are important factors governing the viability of SAGD applications specific situations must be assessed based on actual reservoir properties and other unique factors such as well spacing optimization and costs that may be influenced by other operations in the area.

Table 3.1 — Athabasca McMurray Formation Reservoir Parameters for 2D Overburden Model

Grid. No.	Porosity (PHI)	Water Saturation (Sw)	Oil Saturation (So)	Ki=Kj	Kk
16	0.3	0.25	0.75	2000	200
15	0.3	0.25	0.75	2000	200
14	0.3	0.25	0.75	2000	200
13	0.3	0.25	0.75	2000	200
12	0.3	0.25	0.75	2000	200
11	0.3	0.25	0.75	2000	200
10	0.35	0.15	0.85	10000	2500
9	0.35	0.15	0.85	10000	2500
8	0.3	0.25	0.75	2000	200
7	0.35	0.15	0.85	2000	200
6	0.35	0.15	0.85	2000	200
5	0.3	0.25	0.75	2000	200
⌀ 4	0.35	0.15	0.85	10000	2500
Injector 3	0.35	0.15	0.85	10000	2500
2	0.35	0.15	0.85	10000	2500
● 1	0.35	0.15	0.85	10000	2500

Producer

1.5m grid blocks in the k direction.

Table 3.2

Athabasca McMurray Effect of Overburden Study Performance Forecast and Supply Price Summary Discounted to 10% to 1995 Dollars

Case Study	140m Overburden		100m Overburden		50m Overburden	
Cost Centre	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**
Capital Cost						
Drilling	$12.36	22.38%	$14.01	24.55%	$18.64	29.26%
Seism/Delin/Eng	$0.32	0.59%	$0.34	0.59%	$0.37	0.58%
Steam Facilities	$3.99	7.22%	$3.90	6.84%	$4.41	6.93%
Other Facilities	$12.90	23.35%	$13.49	23.63%	$14.68	23.03%
Total Capital	$29.56	53.53%	$31.74	55.61%	$38.10	59.79%
Operating Cost						
Gas Cost	$13.30	24.08%	$12.82	22.46%	$12.54	19.67%
Utilities	$3.56	6.44%	$3.43	6.01%	$3.36	5.27%
Production Treating	$0.78	1.42%	$0.79	1.38%	$0.80	1.25%
Water Treating	$1.02	1.85%	$0.98	1.72%	$0.95	1.50%
Fixed and Other	$7.00	12.68%	$7.32	12.83%	$7.97	12.50%
Total Operating Cost	$25.66	46.47%	$25.33	44.39%	$25.62	40.20%
Total Cost/m³ BIT	**$55.23**	**100.00%**	**$27.07**	**100.00%**	**$63.72**	**100.00%**
Total Cost/bbl BIT	**$8.78**		**$9.07**		**$10.13**	
Plant Summary						
Cum Bitumen Produced (E^3m^3)	47,117		45,273		44,041	
Cum Steam Injected (E^3m^3)	112,515		104,001		97,362	
Cum Water Produced (E^3m^3)	103,990		95,949		89,835	
Plant CDOR (m^3/d)	4,303		4,135		4,022	
Plant CSOR (m^3/m^3)	2.39		2.3		2.21	
Number of wells	218		218		226	
Plant Efficiency (%)	90.2		86.7		84.3	
Avg. Well Summary						
Pattern Life (yrs)	8.75		10.75		16.75	
Bitumen Produced (E^3m^3)	219		216		210	
Steam Injected (E^3m^3)	502		471		441	
Water Produced (E^3m^3)	489		458		430	
Well CDOR (m^3/d)	69		55		34	
Well CSOR (m^3/m^3)	2.29		2.18		2.1	
Recovery (90m spacing)	79.8%		78.6%		76.4%	

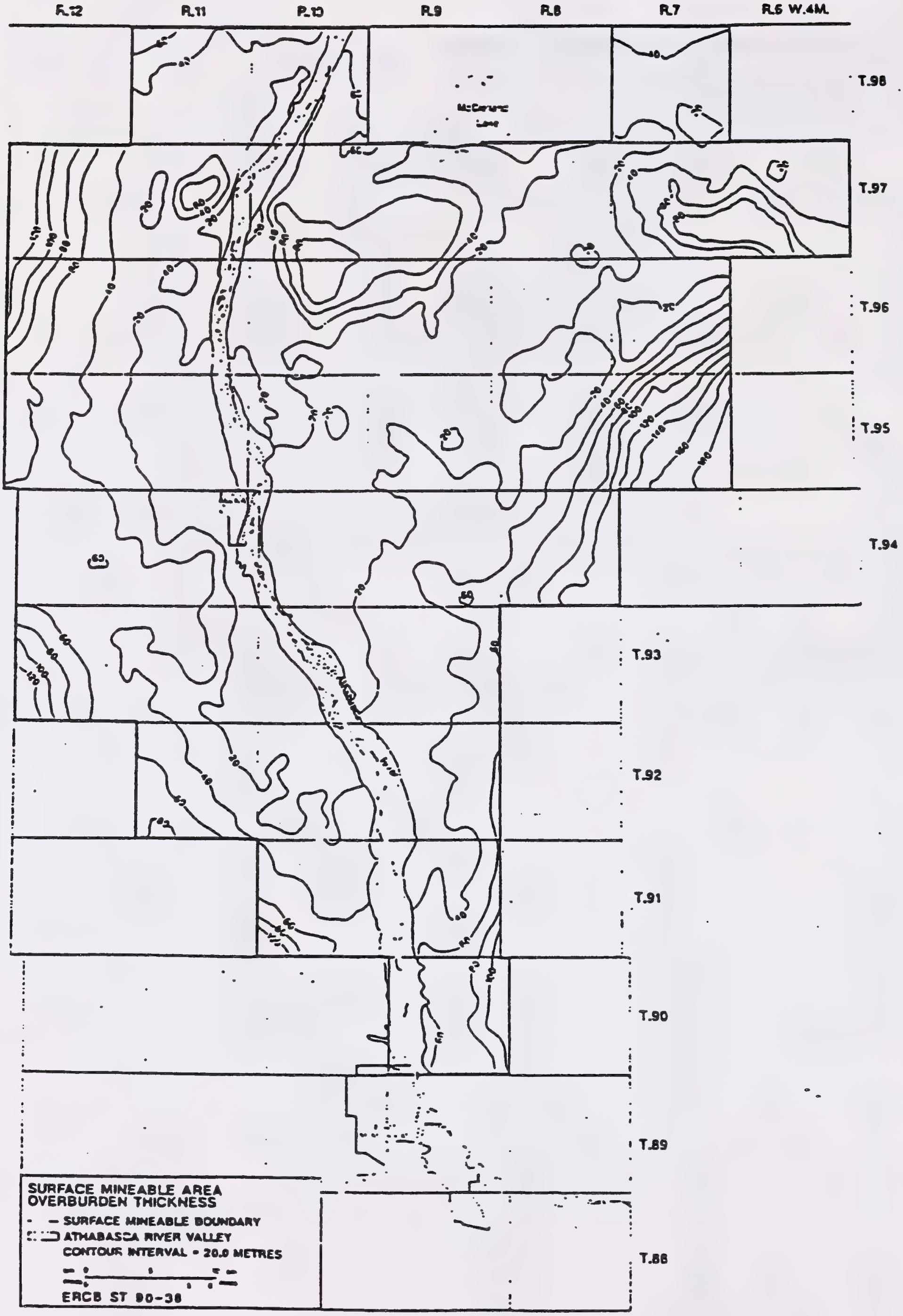


Figure 3.1 — Athabasca Oil Sands Area Wabiskaw — McMurray Deposit

AVERAGE WELL PROFILE FROM SIMULATION RESULTS
Athabasca McMurray - 140 m Overburden

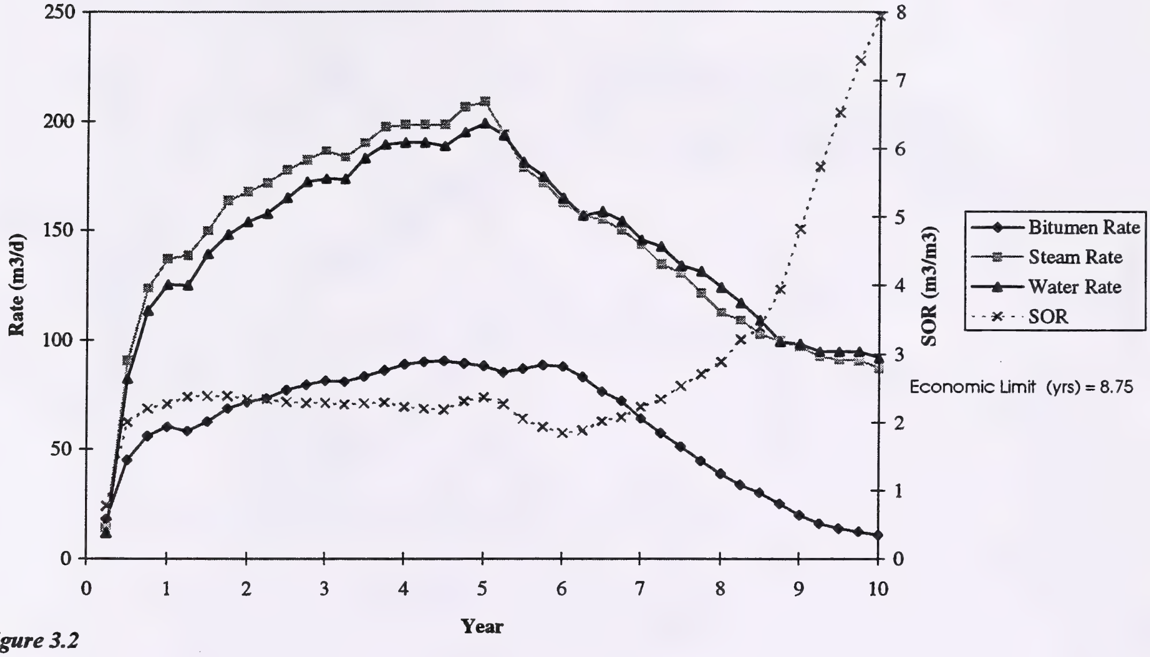


Figure 3.2

AVERAGE WELL PROFILE FROM SIMULATION RESULTS
Athabasca McMurray - 100 m Overburden

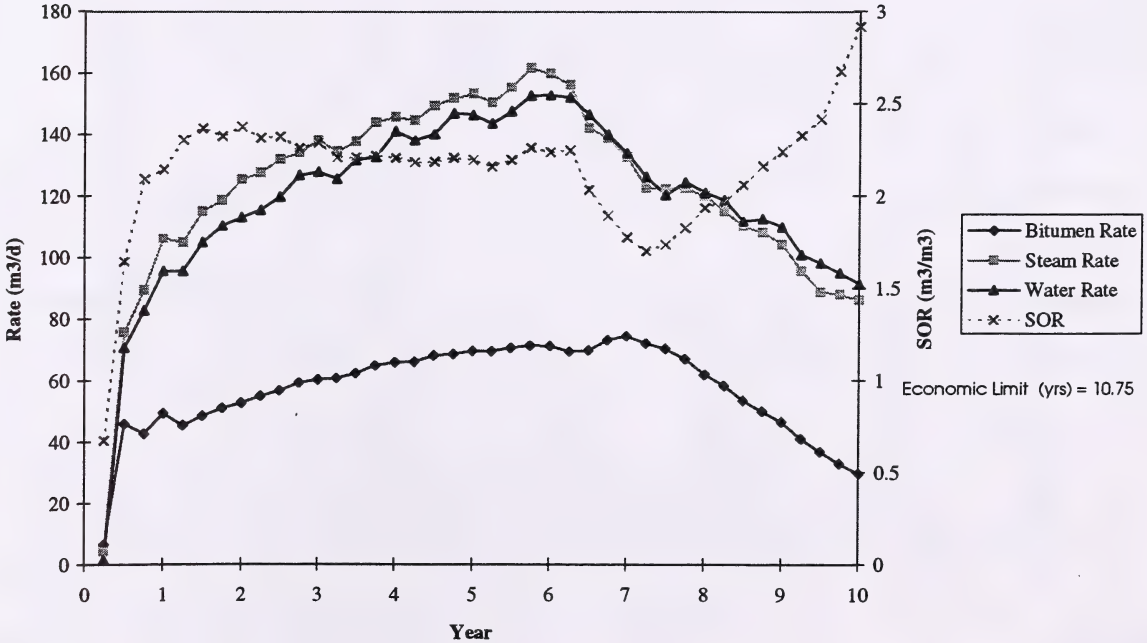


Figure 3.3

AVERAGE WELL PROFILE FROM SIMULATION RESULTS
Athabasca McMurray - 50 m Overburden

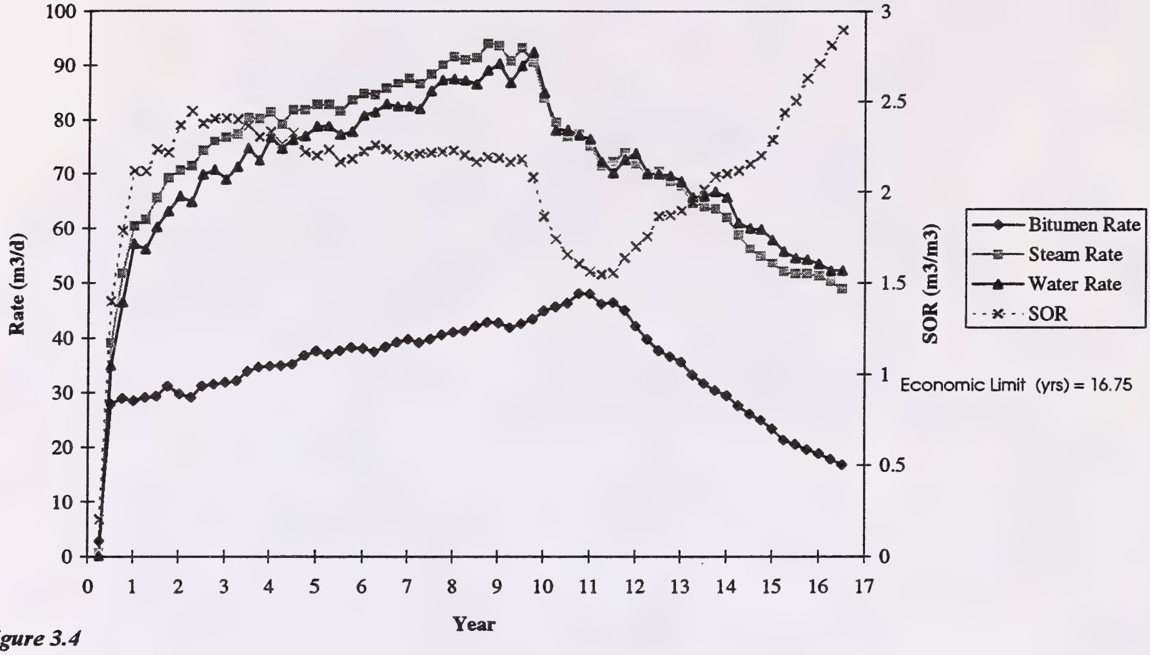


Figure 3.4

PLANT FORECAST
Athabasca McMurray - 140 m Overburden

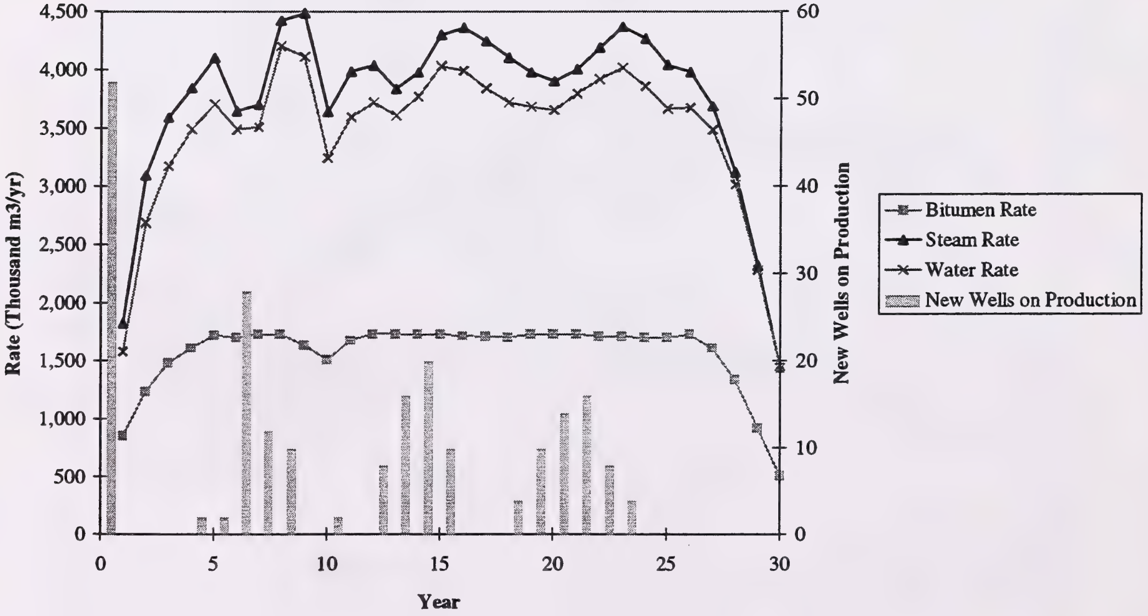


Figure 3.5

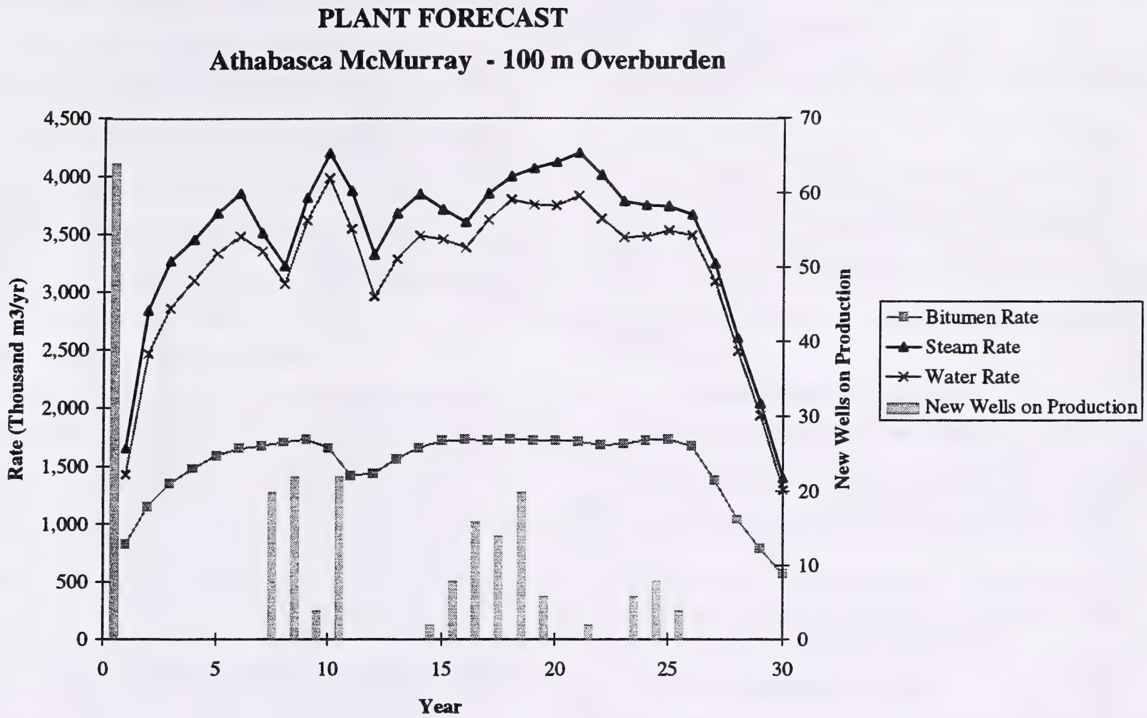

PLANT FORECAST
Athabasca McMurray - 100 m Overburden

Figure 3.6

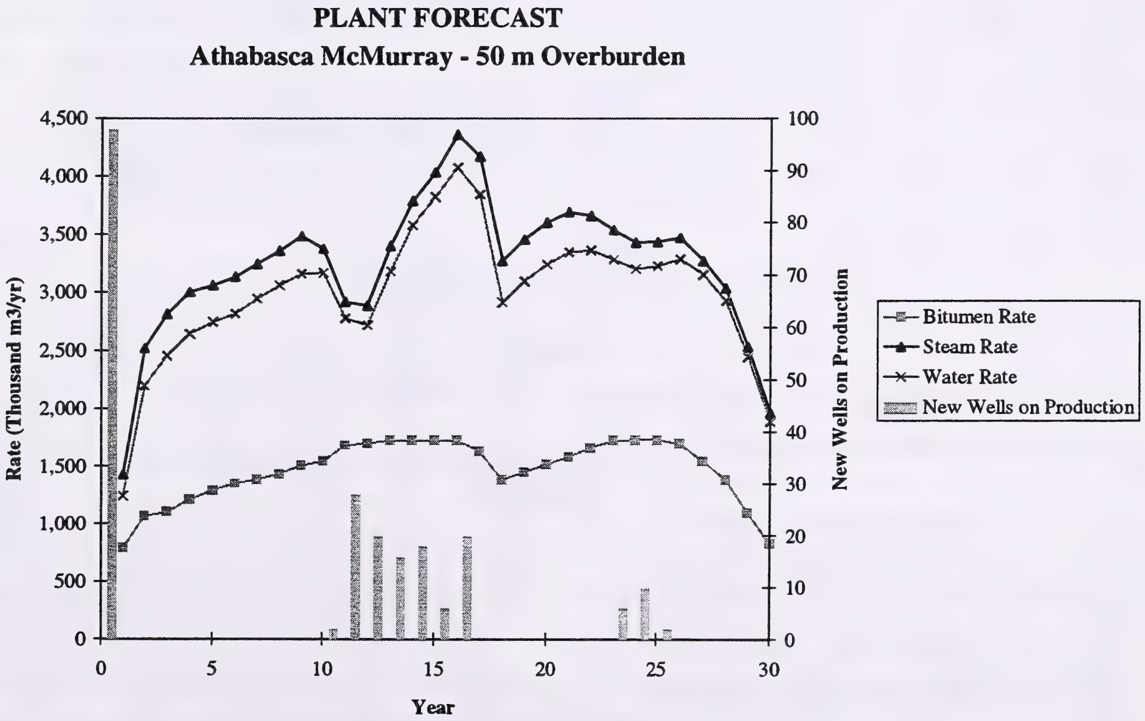

PLANT FORECAST
Athabasca McMurray - 50 m Overburden

Figure 3.7

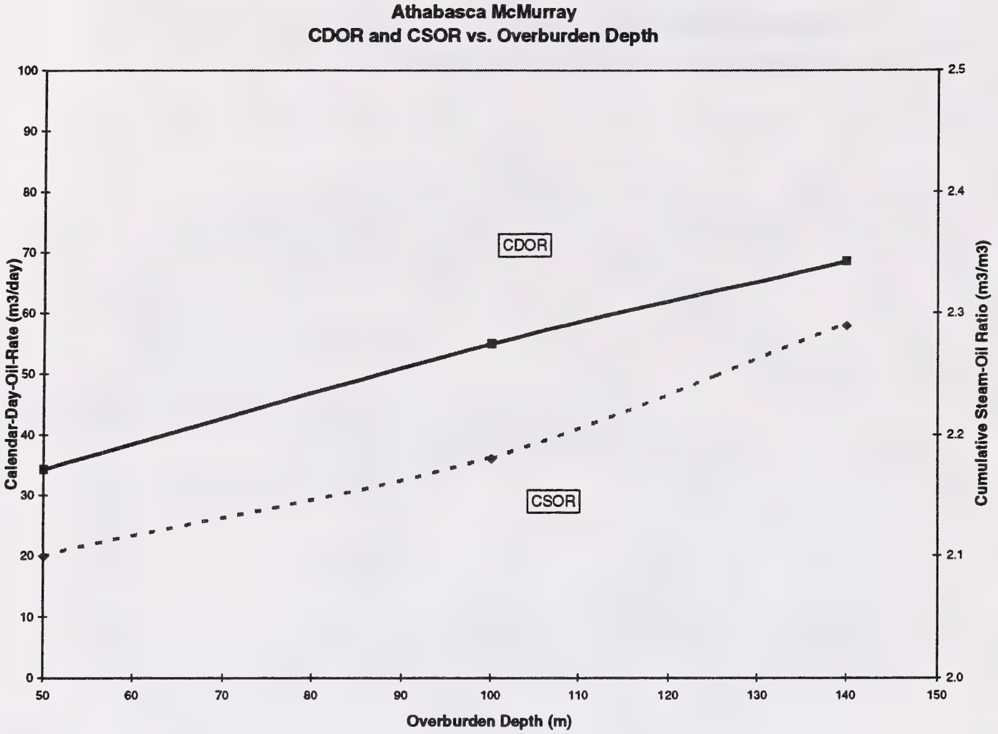


Figure 3.8

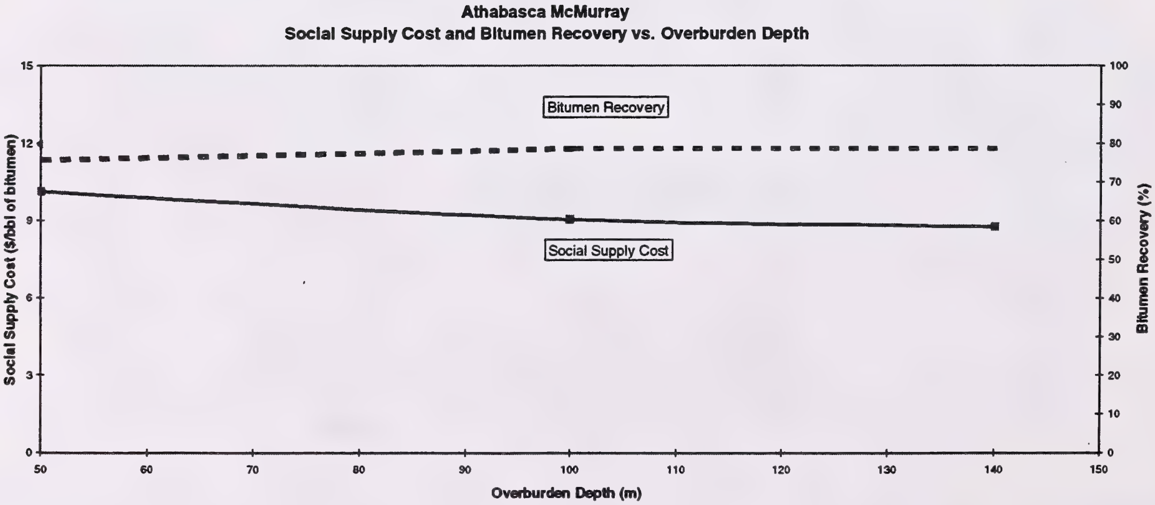


Figure 3.9

4.0 Effect of Net Pay Thickness

The purpose of this component of the study is to evaluate the relationship between net reservoir pay thickness and the SAGD process viability in Athabasca.

From a theoretical perspective, Butler⁽¹⁾ found that the bitumen production rate is proportional to the square root of the pay zone thickness, is not dependent on the shape of the interface between the steam chamber and the unheated bitumen or the steam chambers horizontal extension. He also found that the CSOR is lower with thicker pay as less heat is lost to the over/under-burden.

4.1 Model Description

Four net pay thickness scenarios were simulated to demonstrate the effect of pay thickness on SAGD and to determine a minimum pay thickness for which the process would be feasible. The 24m net pay model used in the overburden effect portion of this study was used as a base case model for the pay thickness study. Other models representing 45m, 16m and 8m of net pay were developed by maintaining grid blocks at 1.5m for 45m pay and scaling the base case by modifying vertical thickness of the grid blocks for the 16m and 8m pay scenarios. Spacing between wells and well pair spacing was maintained at 4.5m and 90m respectively. A steam chamber pressure of 1400 kPa, consistent with the 140m overburden case in the previous section, was used for all thickness cases. A more detailed description of the model is presented in section 3.2.1.

4.2 Simulation Results

The following summarizes simulation results for various net pay thicknesses. Plots of the bitumen and water production and steam injection for each case are also shown on Figures 3.1 and Figures 4.1 to 4.3.

Property Net Pay (m)	Case 4	Case 3	Case 1 (Base Case)	Case 2
Reservoir Pay (m)	8	16	24	45
Pattern Life (years)	3.50	6.50	8.75	17.25
Oil Production (m^3)	39,000	146,000	219,000	472,000
CDOR m^3/day	31	62	69	75
Steam Injection (m^3)	139,000	368,000	502,000	810,000
CSOR	3.57	2.52	2.29	1.85
Recovery (%OOIP)	40.7	73.7	79.8	82.3

Although having the expected trend, the CDOR for 45m net pay (75m^3/day) is lower than theoretically expected. The reason is that CDORs is not the theoretical maximum production rate but is an average oil rate over the pattern life. They are, therefore, influenced by interwell pair spacing and variations in reservoir properties. For example, in the 8m, 16m, 24m and 45m net pay cases, the steam chamber reaches the top of the reservoir after approximately 1.9 years, 2.6 years, 4.8 years and 10.5 years, respectively. The times for the steam chambers to reach the lateral boundaries (45m from the wells), however, is similar allowing for variations in reservoir properties at approximately 5.8 years, 4.7 years, 5.2 years and 3.5 years respectively. The shapes of the steam chamber are somewhat different for the 45m case and may explain the lower than expected CDOR and illustrate the need to optimize the interwell pair spacing. The CSORs decrease from 3.57 for 8m net pay to 1.85 for 45m net pay as expected due to lower heat losses to the over and underburdens for thicker net pays.

4.3 Commercial Projects

The well pair performance plots from the simulations were used to generate well pair drilling schedules and commercial project bitumen and water production and steam injection predictions as shown on Figures 3.5 and Figures 4.4 to 4.6.

The well pairs necessary to supply a 30,000 barrels per day plant for 30 years is 116, 218, 322 and 1158 for 45m, 24m, 16m and 8m net pay thicknesses respectively.

4.4 Social Supply Cost

The social supply costs for the four pay thickness cases are shown on Table 4.1 and summarized as follows:

	Case 4	Case 3	Case 1 (Base Case)	Case 2
Reservoir Pay (m)	8	16	24	45
Pattern Life (yrs)	3.50	6.50	8.75	17.25
Social Supply Cost ($bbl)	15.74	9.35	8.78	7.35
Plant Production ($E6m^3$)	45.2	46.9	47.2	47.8
Plant Efficiency (%) For 30 Years	86.5	89.7	90.2	91.7
Total Wells	1158	322	218	116

As shown, the social supply costs increase from $7.35/bbl to $15.74/bbl with net pay decreasing from 45m to 8m. As noted in 4.2, the bitumen recovery decreases from 82.3% to 40.7% over the same net pay range.

4.5 Summary and Findings

Cumulative calendar day oil rates (CDOR) and cumulative steam oil ratios (CSOR) for various net pay thicknesses are plotted on Figure 4.7. As discussed previously, the effect of interwell pair spacing and reservoir parameter distribution is believed to have resulted in a pessimistic value of CDOR from the 45m net pay thickness simulation and explains the

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(1) "Thermal Recovery of Oil and Bitumen," by R.M. Butler, 1991, published by Prentice-Hall

apparent change in a decline trend between 16m and 8m of net pay. The more rapid increase in CSOR at net pays below 16m is believed due to a greater portion of the steam consumed by heat losses to the over and underburden for thinner pay sections.

Social supply costs and bitumen recoveries are plotted versus net pay thickness on Figure 4.8. These plot also show a dramatic decrease in bitumen recovery and increase in social supply cost for net pay thicknesses less than about 15 metres. The decrease in bitumen recovery from 74% for 16m net pay to 41% for 8m net pay is due primarily to the maximum bitumen production rate for 8m net pay, being much closer to the economic limit, reaching it earlier significantly affecting bitumen recovery. Increased drilling costs of almost \$5/bbl and gas costs of almost \$1/bbl are the major contributors to social supply costs increasing from \$9.35/bbl for 16m net pay to \$15.74/bbl for 8m net pay.

It appears that a current reasonable minimum reservoir thickness in which the dual well SAGD process can be applied is 15m based on the assumed reservoir quality and steam chest operating pressure. It stressed, however, that this minimum thickness will be dependent upon a number of factors such as reservoir quality and steam chamber operating pressures.

Table 4.1

Athabasca McMurray Effect of Net Pay Thickness Study Performance Forecast and Supply Price Summary Discounted to 10% to 1995 Dollars

Case Study	8m Net Pay Thickness		16m Net Pay Thickness		24m Net Pay Thickness		45m Net Pay thickness	
Cost Centre	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**
Capital Cost								
Drilling	\$45.37	45.83%	\$14.39	24.47%	\$12.36	22.38%	\$7.97	17.23%
Seism/Delin/Eng	\$0.31	0.31%	\$0.32	0.54%	\$0.32	0.59%	\$0.31	0.67%
Steam Facilities	\$6.09	6.15%	\$4.23	7.18%	\$3.99	7.22%	\$3.33	7.21%
Other Facilities	\$12.19	12.32%	\$12.65	21.51%	\$12.90	23.35%	\$12.42	26.86%
Total Capital	\$63.96	64.60%	\$31.59	53.71%	\$29.56	53.53%	\$24.04	51.97%
Operating Cost								
Gas Cost	\$20.59	20.79%	\$14.56	24.76%	\$13.30	24.08%	\$10.93	23.64%
Utilities	\$5.49	5.54%	\$3.90	6.62%	\$3.56	6.44%	\$2.94	6.35%
Production Treating	\$0.78	0.78%	\$0.78	1.33%	\$0.78	1.42%	\$0.78	1.68%
Water Treating	\$1.57	1.59%	\$1.12	1.90%	\$1.02	1.85%	\$0.85	1.78%
Fixed and Other	\$6.62	6.69%	\$3.87	11.68%	\$7.00	12.68%	\$6.74	14.58%
Total Operating Cost	\$35.04	35.40%	\$27.23	46.29%	\$25.66	46.47%	\$22.21	48.03%
Total Cost/m³ BIT	**\$99.00**	**100.00%**	**\$58.82**	**100.00%**	**\$55.23**	**100.00%**	**\$46.25**	**100.00%**
Total Cost/bbl BIT	**\$15.74**		**\$9.35**		**\$8.78**		**\$7.35**	
Plant Summary								
Cum Bitumen Produced (E^3m^3)	45,164		46,874		47,117		47,838	
Cum Steam Injected (E^3m^3)	169,822		124,251		112,515		94,460	
Cum Water Produced (E^3m^3)	155,068		114,679		103,990		86,957	
Plant CDOR (m^3/d)	4,125		4,281		4,303		4,369	
Plant CSOR (m^3/m^3)	3.76		2.65		2.39		1.97	
Number of wells	1158		322		218		116	
Plant Efficiency (%)	86.5		89.8		90.3		91.7	
Avg. Well Summary								
Pattern Life (yrs)	3.5		6.5		8.75		17.25	
Bitumen Produced (E^3m^3)	39		146		219		472	
Steam Injected (E^3m^3)	139		368		502		870	
Water Produced (E^3m^3)	134		357		489		860	
Well CDOR (m^3/d)	31		62		69		75	
Well CSOR (m^3/m^3)	3.57		2.52		2.29		1.85	
Recovery (90m spacing)	40.7%		73.7%		79.8%		82.3%	

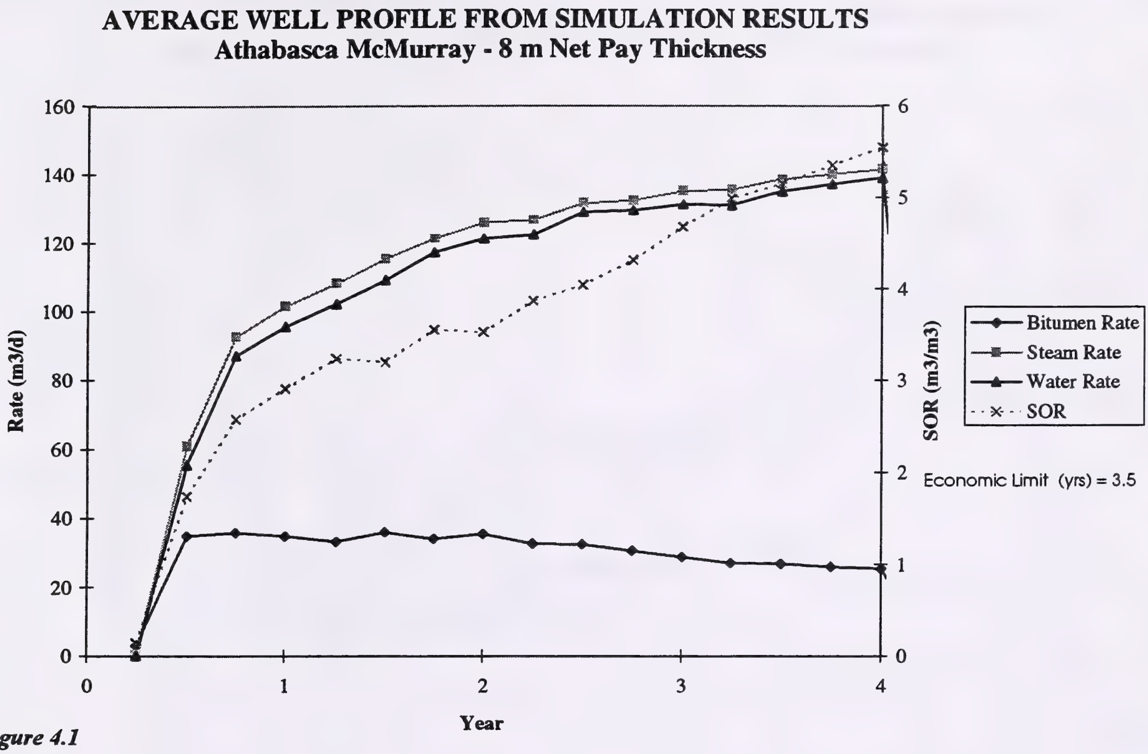

AVERAGE WELL PROFILE FROM SIMULATION RESULTS
Athabasca McMurray - 8 m Net Pay Thickness

Figure 4.1

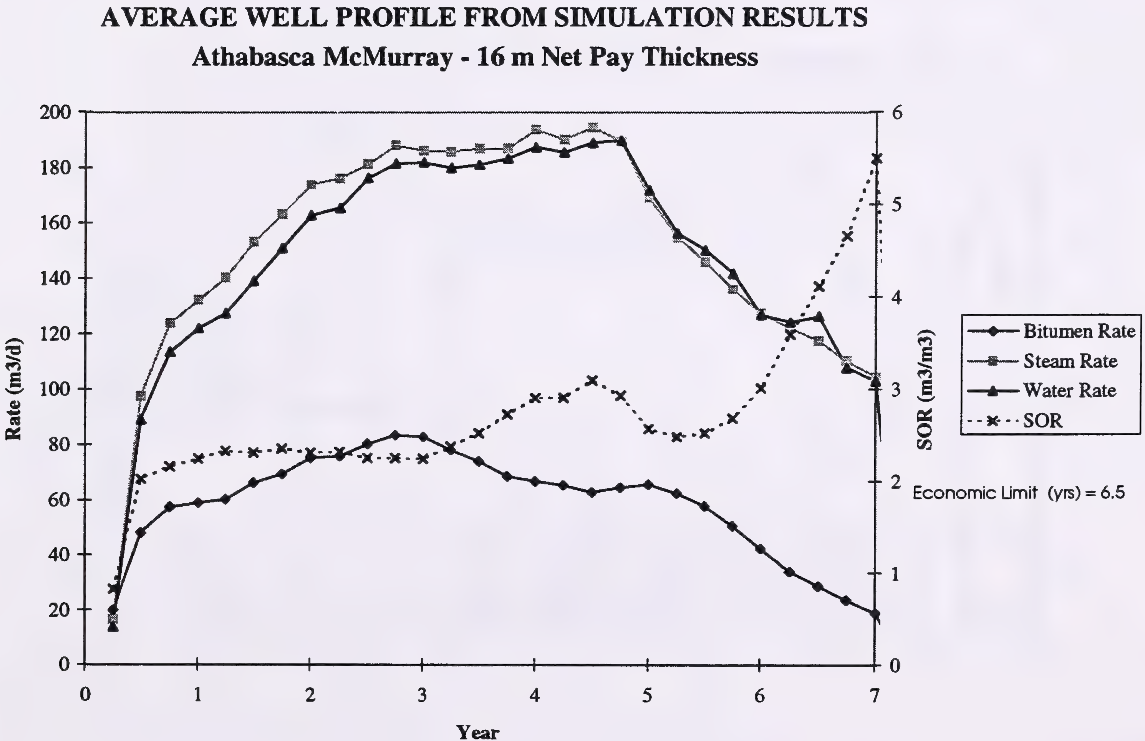

AVERAGE WELL PROFILE FROM SIMULATION RESULTS
Athabasca McMurray - 16 m Net Pay Thickness

Figure 4.2

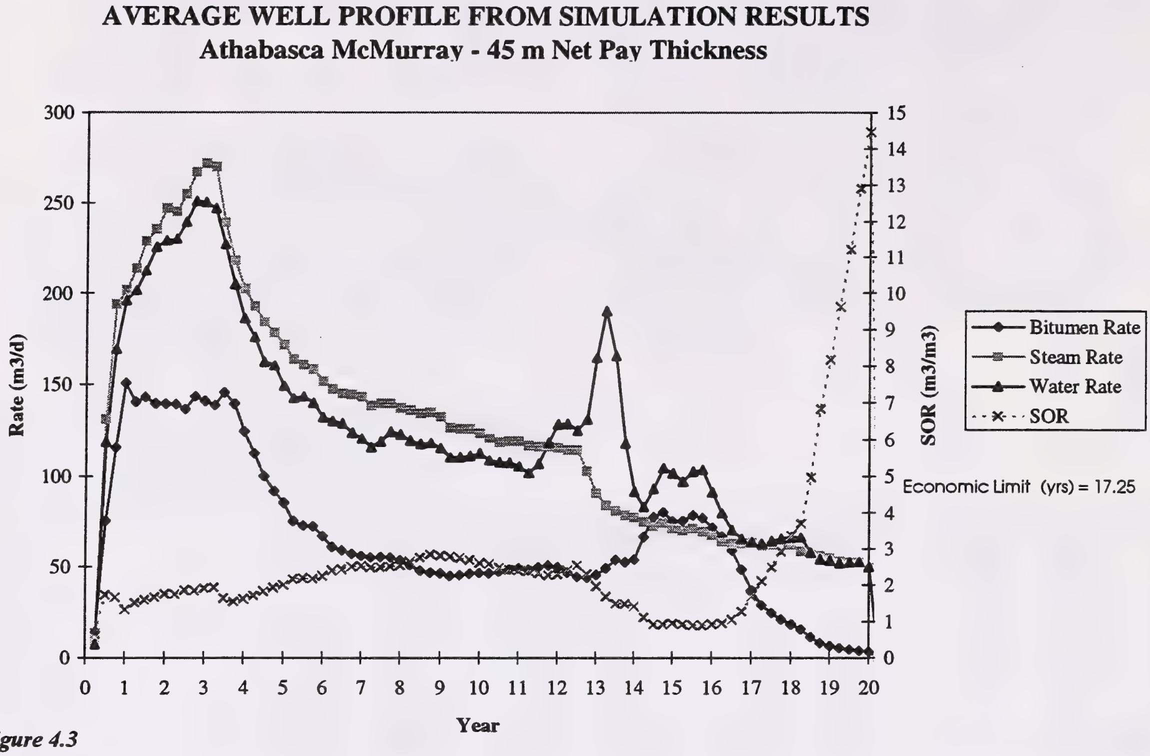


Figure 4.3

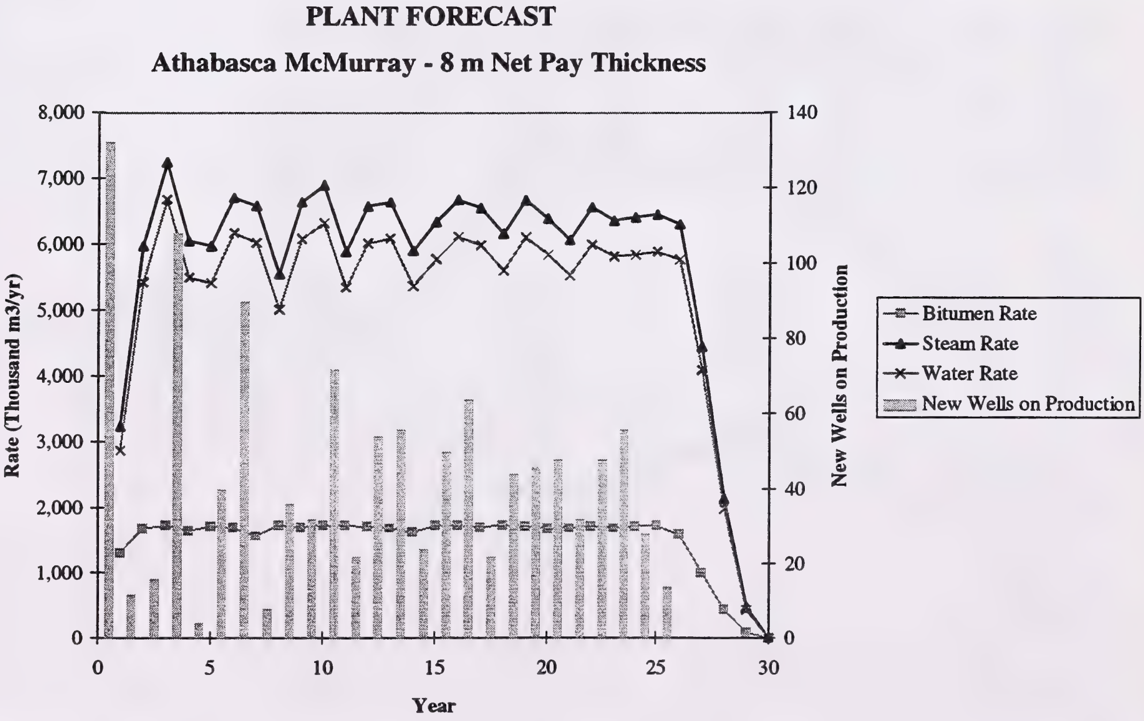


Figure 4.4

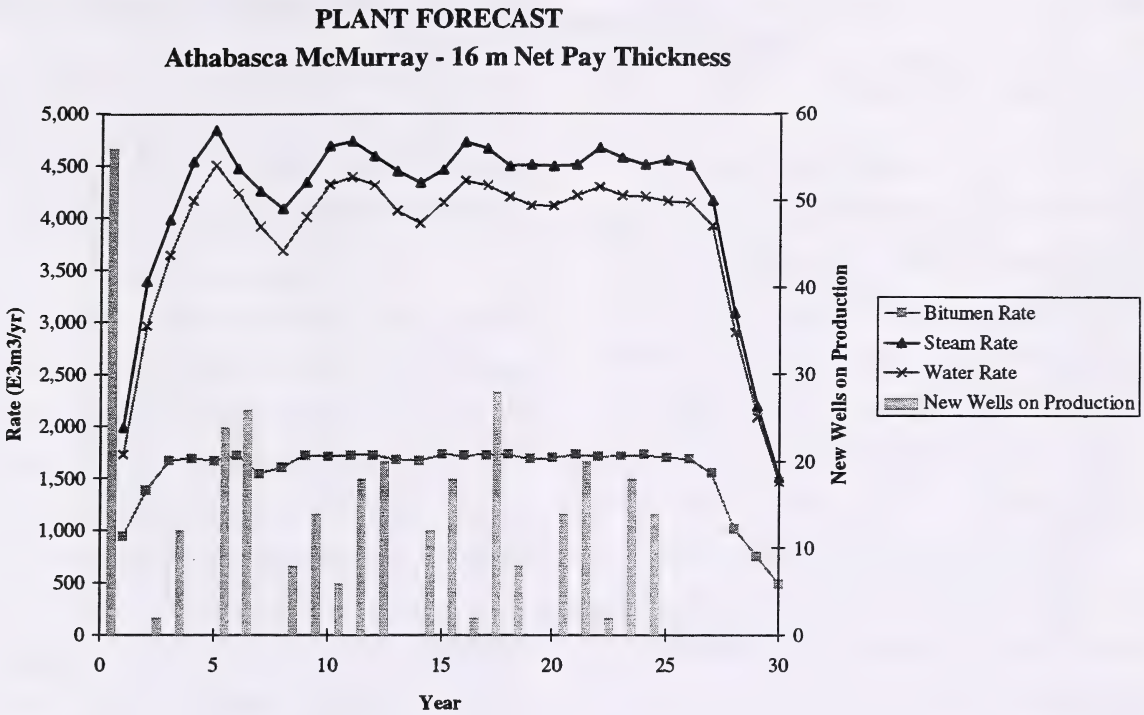


Figure 4.5

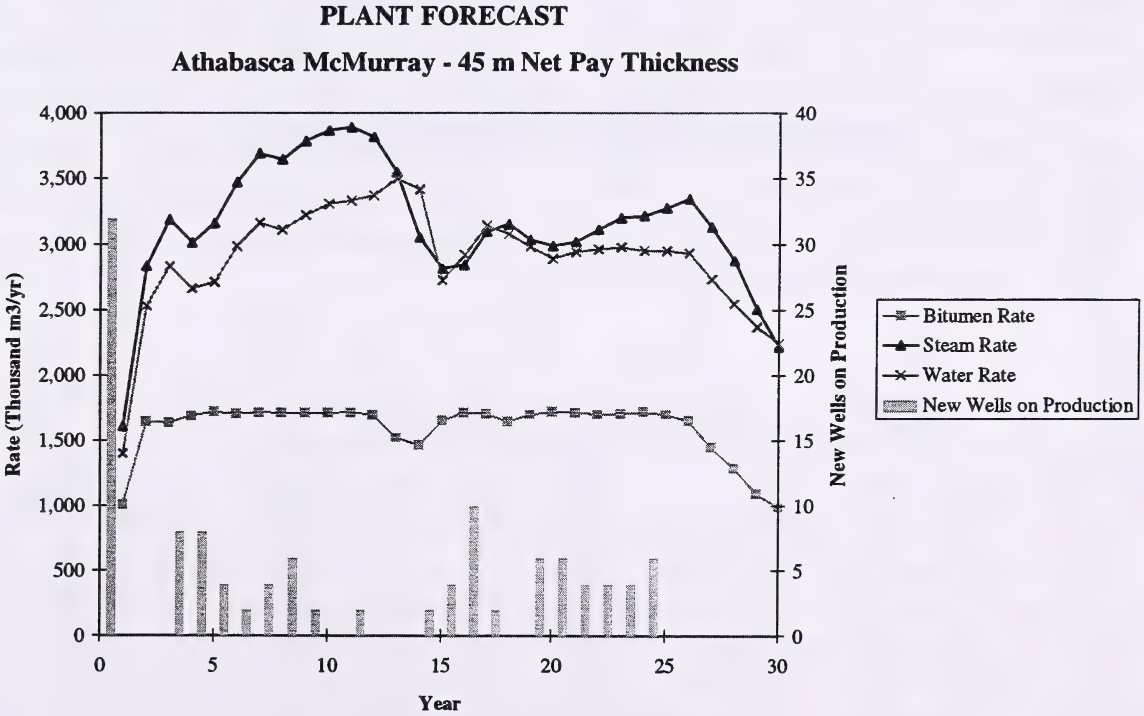


Figure 4.6

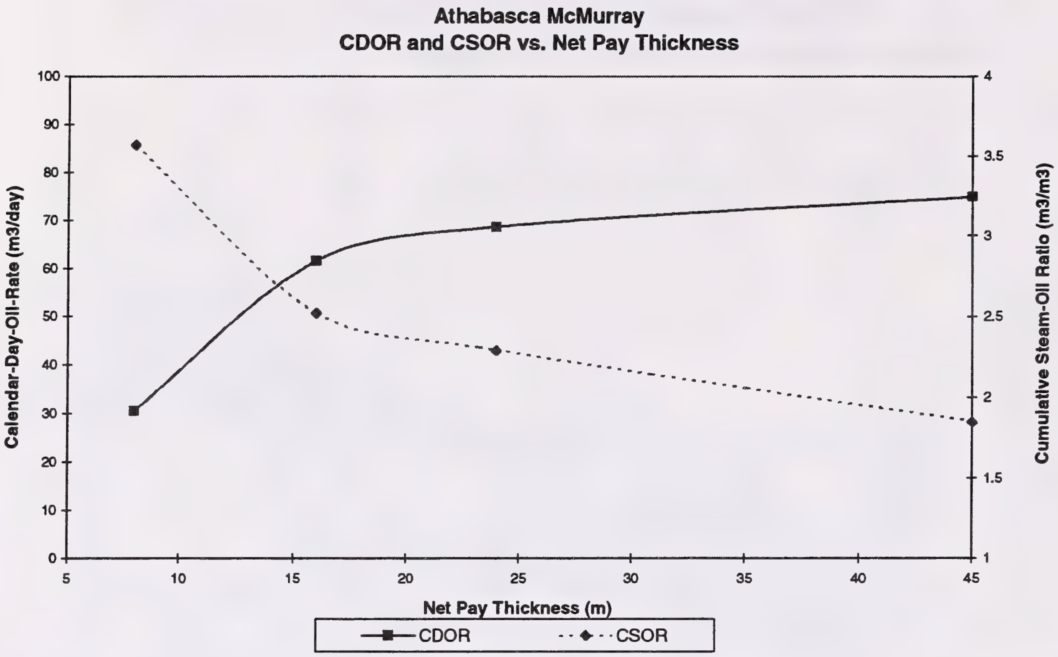


Figure 4.7

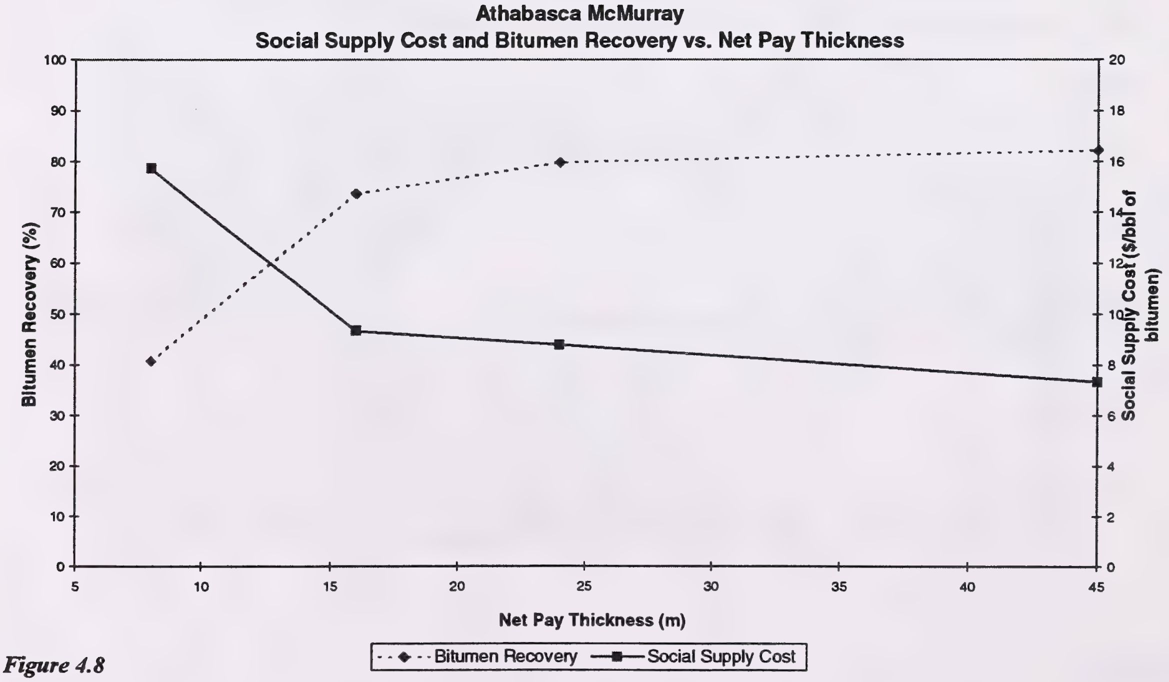


Figure 4.8

5.0 Effect of Overlying Water

The effect of gas caps on SAGD performance was addressed in the companion to this report. Gas caps in the Athabasca McMurray formation, however, are quite often associated with water sands overlying the oil sand. The effect of these water sands on SAGD performance with and without gas caps using numerical simulation has been assessed and is reported in this section.

5.1 Model Description

The model used to study the effect of water sands and combinations of gas caps and water sands on SAGD performance is the 3D, three well pair configurations used to study gas cap effects described in the companion report. For purposes of clarification Table 5.1 describes the reservoir properties included in the model and Figure 5.1 shows the well pairs and model configuration. The model consists of 24m of oil sand net pay overlain by combinations of 0m, 5m and 10m thicknesses of gas and/or water sand. The reservoir properties of the gas sands are 30% porosity, 2000 mD horizontal permeability, 200 mD vertical permeability, 80% initial gas saturation and 20% initial water saturation. No initial bitumen saturation was assigned to the gas sands, however, a 20% residual bitumen saturation was assigned. The porosity and permeabilities of the water sands were the same as for the gas sands, however, 80% and 20% initial water and bitumen saturations were assigned respectively. The grid block sizes used for the gas cap and water sands were the same as for the oil sand with exception of the vertical dimension which was increased from 1.5m to 2.5m. Steam injection and bitumen and water productions were simulated for both non-depleted (1800 kPa) and depleted (550 kPa) gas and/or water sand pressures with steam chamber pressures of 2600 kPa for a base (no water or gas cap) case and five combinations of overlying gas and water sand thicknesses.

Although the model provides a reasonable prediction of SAGD performance with no gas or overlying water, it's reliability with gas caps and overlying water sands is unproven to date. The results must, therefore, be used with caution.

5.2 Simulation Results

The table below summarizes the performance of typical well pair performance for the cases simulated.

The target steam chamber operating pressure in each case was 2600 kPa but steam injection rates were limited to a maximum of 400 m^3 per day per well pair. These maximum rates limited injection to varying degrees in all of the 10m sands with exception of the 10m non-depleted gas sand for which outflow at the gas cap was restricted.

Individual well pair steam injection and bitumen and water production predictions for the 5m water sand and 5m gas plus 5m water sand and 10m water sand cases for both non-depleted and depleted cases are shown on Figures 5.2 to 5.7. Well pair forecasts for the other cases, 0m, 5m and 10m gas caps, were presented in the companion report addressing gas cap effects and are not repeated here.

Of particular interest in analyzing the migration of steam into the overlying gas and water sands is the possibility of bitumen moving into these sands ahead of or with the steam, cooling and then acting as a partial plug in restricting the loss of steam. This is a very complex mechanism and may not be represented correctly by the model used to simulate performance. At this time, however, these models are our best means of predicting performance.

Simulated productions of gas, water and bitumen from the gas or water sand back pressure well and bitumen saturation cross-section profiles in later pattern life are included with simulation output in Appendix 3. Three criteria were used to analyze the output for impact of overlying gas and water sands; outflow volume during the pattern life, lateral extension of the steam chamber past the normal

	Non-depleted				Depleted			
Overlying Gas and Water Sand Thickness	CDOR (m^3/d)	CSOR	Recovery (%)	Pattern Life (Yrs)	CDOR (m^3/d)	CSOR	Recovery (%)	Pattern Life (Yrs)
0m gas/0m water	79	2.70	82.3	8.25	80	2.72	81.1	8.00
0m gas/5m water	84	2.92	73.8	7.25	83	2.96	73.6	7.25
5m gas/0m water	80	3.08	75.4	7.50	81	3.33	73.2	7.25
5m gas/5m water	77	3.87	70.5	7.25	72	4.64	69.2	7.50
0m gas/10m water	78	3.02	78.6	8.25	76	4.33	64.8	7.25
10m gas/0m water	78	3.58	73.8	7.50	69	5.12	63.4	7.25

outside boundary of the pattern, and bitumen volume which moved into the gas cap and water sand beyond the steam chamber at the end of the pattern life. Estimates of these criteria are plotted on Figures 5.8(a), (b) and (c). Comparison of the pattern outflow and lateral extension of the steam chamber for various types, thicknesses and pressures of overlying sands show that both outflow and steam zone width increase with increasing overlying gas cap and/or water sand thickness and with increasing pressure differential between the steam chamber and overlying sand (a high back pressure of 1800 kPa has a differential pressure of up to 800 kPa whereas a low back pressure of 550 kPa has a differential pressure of up to 2050 kPa).

The volume of bitumen moved into the overlying gas cap and water sand beyond the steam chamber was estimated from bitumen saturation cross section profiles and plotted as m^3 of bitumen per metre of well length in Figure 5.8(c). These bitumen volumes in some cases relate to the outflow and steam chamber extension as expected. Although partial plugging may be occurring, it is not evident from this data.

5.3 Commercial Project

The well pair performance plots from the simulation runs were used to generate well pair drilling schedules and commercial project bitumen and water production and steam injection predictions as shown on Figures 5.9 to 5.14. The well pairs necessary to supply a 30,000 barrels per day plant for 30 years is fairly similar varying from 202 to 248.

5.4 Social Supply Costs

The social supply costs for the cases studied are tabulated on Table 5.2 and together with the number of well pairs and bitumen recoveries are summarized in the table below.

Social supply costs vary from a low of $9.12/bbl of bitumen for no overlying gas or water to $12.99/bbl for a 10m gas cap. Pattern bitumen recoveries vary from a high of 82.3% for no overlying gas or water to a low of 63.4% for a 10m gas cap. As expected, social supply costs are generally higher for depleted compared to non-depleted overlying gas and/or water sands and are higher for thicker overlying gas and/or water sands.

5.5 Summary and Findings

Bitumen recoveries and social supply costs are compared for various overlying gas and/or water sand thickness and depletion on Figures 5.15 and 5.16. As mentioned previously, bitumen supply costs seem to increase with increasing thickness of the overlying gas and water sands and are generally higher for depleted than non-depleted pressure. With exception of the non-depleted 10m gas cap case, in which the gas production rate at the gas cap constant pressure well was restricted resulting in better performance, water sands appear to have a less negative impact on social supply costs than gas caps. Recovery decreases with increasing gas cap and water sands thickness and is generally less for depleted as compared to non-depleted pressures. With the exception of the 5m gas and water non-depleted cases, bitumen recovery is also better with the water sands than gas caps. Although the effect of overlying water sand and gas sand are not significantly different, the mechanisms involved with steam breaking into an overlying water sand are unknown and may be more complex than for a gas cap. Where as the negative effect of steam breaking into a gas zone may be mitigated by gravity segregation of the gas and steam, steam breaking into a water zone does not have the same segregation. Steam must heat the water to steam conditions as the water drains into the steam chamber and displace it from the steam chamber area to prevent quenching the SAGD process by the water. Laboratory and field testing is warranted to better understand the mechanisms involved and verify the numerical model.

	Non-depleted			Depleted		
Overlying Gas and Water Sand Thickness	SSC ($/bbl)	No. of Well Pairs	Bitumen Recovery (%)	SSC ($/bbl)	No. of Well Pairs	Bitumen Recovery (%)
0m gas/0m water	9.12	202	82.3	9.15	202	81.1
0m gas/5m water	9.58	208	73.8	9.56	210	73.6
5m gas/0m water	9.80	214	75.4	10.17	214	73.2
5m gas/5m water	11.17	222	70.5	12.39	222	69.2
0m gas/10m water	10.91	222	78.6	11.65	240	64.8
10m gas/0m water	10.63	218	73.8	12.99	248	63.4

Table 5.1

Athabasca McMurray Formation Reservoir Parameters for 3D Model

	J=2 (400m)					J=1 (100m)				
Grid. No.	Phi	Sw	So	Ki=Kj	Kk	Phi	Sw	So	Ki=Kj	Kk
13 - ?	0.30	*	*	2000	200	0.30	*	*	2000	200
12	0.30	0.25	0.75	2000	200	0.30	0.25	0.75	2000	200
11	0.30	0.25	0.75	2000	200	0.30	0.25	0.75	2000	200
10	0.30	0.25	0.75	2000	200	0.30	0.25	0.75	2000	200
9	0.30	0.25	0.75	2000	200	0.30	0.25	0.75	2000	200
8	0.35	0.15	0.85	10000	2500	0.30	0.25	0.75	2000	200
7	0.35	0.15	0.85	10000	2500	0.35	0.15	0.85	10000	5000
6	0.30	0.25	0.75	2000	200	0.35	0.25	0.85	10000	5000
5	0.35	0.15	0.85	10000	2500	0.35	0.15	0.85	10000	5000
4	0.30	0.25	0.75	2000	200	0.35	0.15	0.85	10000	5000
3	0.35	0.15	0.85	10000	2500	0.35	0.15	0.85	10000	5000
2	0.35	0.15	0.85	10000	2500	0.35	0.15	0.85	10000	5000
1	0.35	0.15	0.85	10000	2500	0.35	0.15	0.85	10000	5000

2m grid blocks in the k direction

* Variable, see discussion

Table 5.2

Athabasca McMurray Effect of Overlying Gas and/or Water Study
Well Forecasts and Supply Price Summary

Discounted @10% to 1995 Dollars

	High Pressure (1800 kPa) Cases						**Low Pressure (550 kPa) Cases**					
	0m Gas Cap 0m Water Sands	0m Gas Cap 5m Water Sands	5m Gas Cap 0m Water Sands	5m Gas Cap 5m Water Sands	0m Gas Cap 10m Water Sands	10m Gas Cap 0m Water Sands	0m Gas Cap 0m Water Sands	0m Gas Cap 5m Water Sands	5m Gas Cap 0m Water Sands	5m Gas Cap 5m Water Sands	0m Gas Cap 10m Water Sands	10m Gas Cap 0m Water Sands
Cost Centre	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**	**Supply Cost**
Capital Cost												
Drilling	$11.16	$11.62	$11.61	$12.33	$11.91	$11.92	$11.13	$11.46	$11.57	$12.98	$12.31	$13.20
Seism/Delin/Eng	$0.32	$0.32	$0.32	$0.34	$0.32	$0.33	$0.32	$0.32	$0.32	$0.34	$0.32	$0.33
Steam Facilities	$4.72	$5.14	$5.50	$7.49	$7.22	$6.34	$4.76	$5.12	$5.88	$8.17	$7.90	$9.06
Other Facilities	$12.64	$12.83	$12.72	$13.38	$12.93	$13.00	$12.60	$12.63	$12.68	$13.68	$12.73	$13.35
Total Capital	$28.83	$29.91	$30.15	$33.52	$32.38	$31.59	$28.81	$29.53	$30.45	$35.18	$33.26	$35.95
Operating Cost												
Gas Cost	$15.53	$16.84	$17.85	$21.55	$21.37	$20.56	$15.69	$17.12	$19.42	$26.33	$24.48	$28.88
Utilities	$4.16	$4.50	$4.77	$5.78	$5.73	$5.50	$4.20	$4.57	$5.18	$7.03	$6.56	$7.72
Production Treating	$0.78	$0.78	$0.78	$0.79	$0.78	$0.78	$0.78	$0.78	$0.78	$0.79	$0.78	$0.79
Water Treating	$1.20	$1.25	$1.21	$1.37	$1.35	$1.33	$1.20	$1.26	$1.25	$1.20	$1.29	$1.13
Fixed and Other	$6.86	$6.96	$6.90	$7.28	$7.02	$7.06	$6.84	$6.85	$6.88	$7.43	$6.91	$7.25
Total Operating Cost	$28.52	$30.34	$31.52	$36.74	$36.25	$35.24	$28.71	$30.59	$33.51	$42.78	$40.02	$45.77
Total Cost/m³ BIT	$57.35	$60.24	$61.66	$70.26	$68.63	$66.83	$57.52	$60.12	$63.96	$77.96	$73.28	$81.72
Total Cost/bbl BIT	$9.12	$9.58	$9.80	$11.17	$10.91	$10.63	$9.15	$9.56	$10.17	$12.39	$11.65	$12.99
Plant Summary												
Number of wells	202	208	214	222	222	218	202	210	214	222	240	248
Cum Bitumen Produced (E^3m^3)	47,297	45,781	46,582	44,648	47,318	46,097	46,754	46,072	45,618	43,629	47,238	44,944
Cum Steam Injected (E^3m^3)	133,872	140,847	151,169	180,745	188,494	173,632	133,320	143,517	159,774	213,030	214,753	241,894
Cum Water Produced (E^3m^3)	123,849	125,555	123,163	136,063	140,690	136,465	122,936	126,660	124,360	114,768	134,447	110,993
Plant CDOR (m^3/d)	4,319	4,181	4,254	4,077	4,321	4,210	4,270	4,208	4,166	3,984	4,314	4,104
Plant CSOR (m^3/m^3)	2.83	3.08	3.25	4.05	3.98	3.77	2.85	3.12	3.50	4.88	4.55	5.38
Bitumen Capacity Utilization	90.6%	87.7%	89.2%	85.5%	90.6%	88.3%	89.5%	88.2%	87.3%	83.5%	90.4%	86.1%
Steam Capacity Utilization	96.7%	95.4%	95.7%	97.3%	83.9%	96.2%	96.1%	95.5%	95.2%	95.5%	97.3%	95.1%
Avg. Well Summary												
Pattern Life (yrs)	8.25	7.25	7.50	7.25	8.25	7.50	8.00	7.25	7.25	7.50	7.25	7.25
Cum Bitumen Produced (E^3m^3)	237	221	219	205	236	214	234	221	214	197	201	181
Cum Steam Injected (E^3m^3)	641	646	676	792	712	766	634	653	711	916	871	928
Cum Water Produced (E^3m^3)	624	606	580	626	664	634	616	607	582	520	576	448
Well CDOR (m^3/d)	79	84	80	77	78	78	80	83	81	72	76	69
Well CSOR (m^3/m^3)	2.70	2.92	3.08	3.87	3.02	3.58	2.72	2.96	3.33	4.64	4.33	5.12
Recovery (90m spacing)	82.3%	73.8%	75.4%	70.5%	78.6%	73.8%	81.1%	73.6%	73.2%	69.2%	64.8%	63.4%

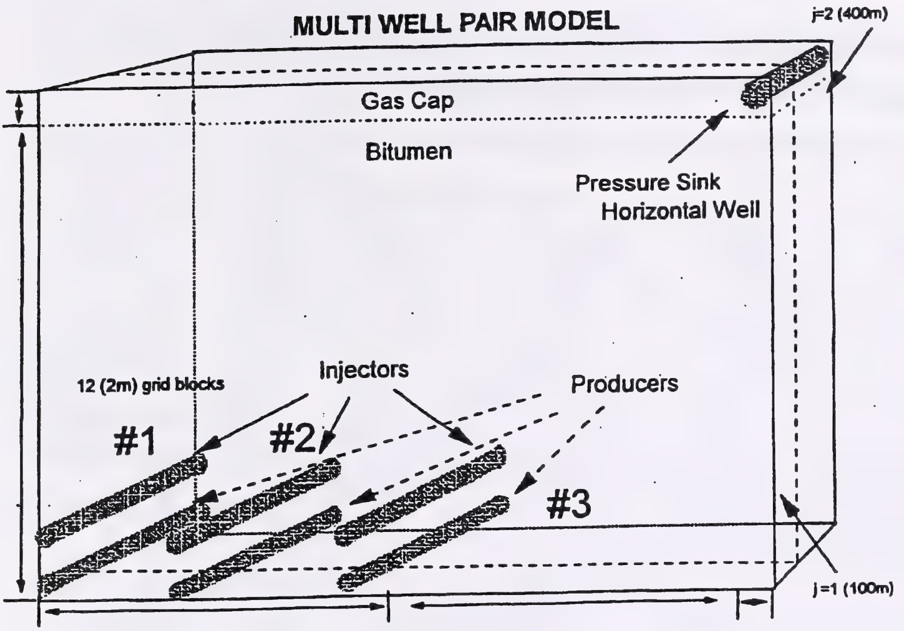


Figure 5.1 — Schematic of 3D Multi-Well-Pair Model

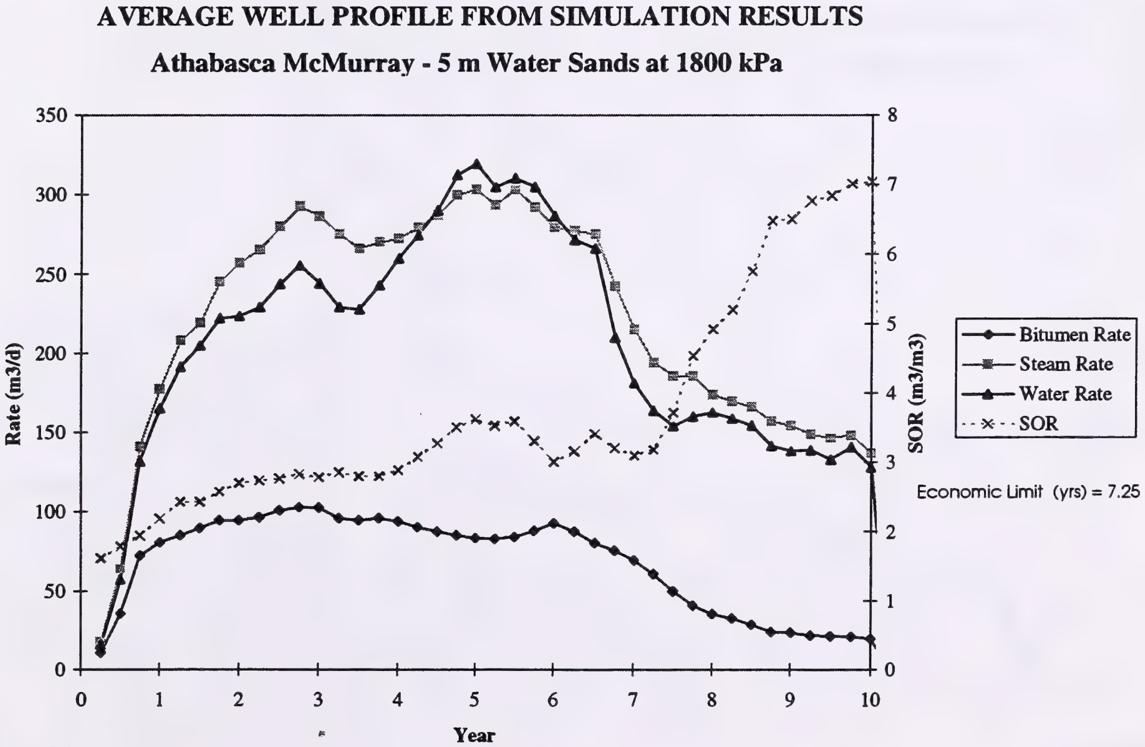
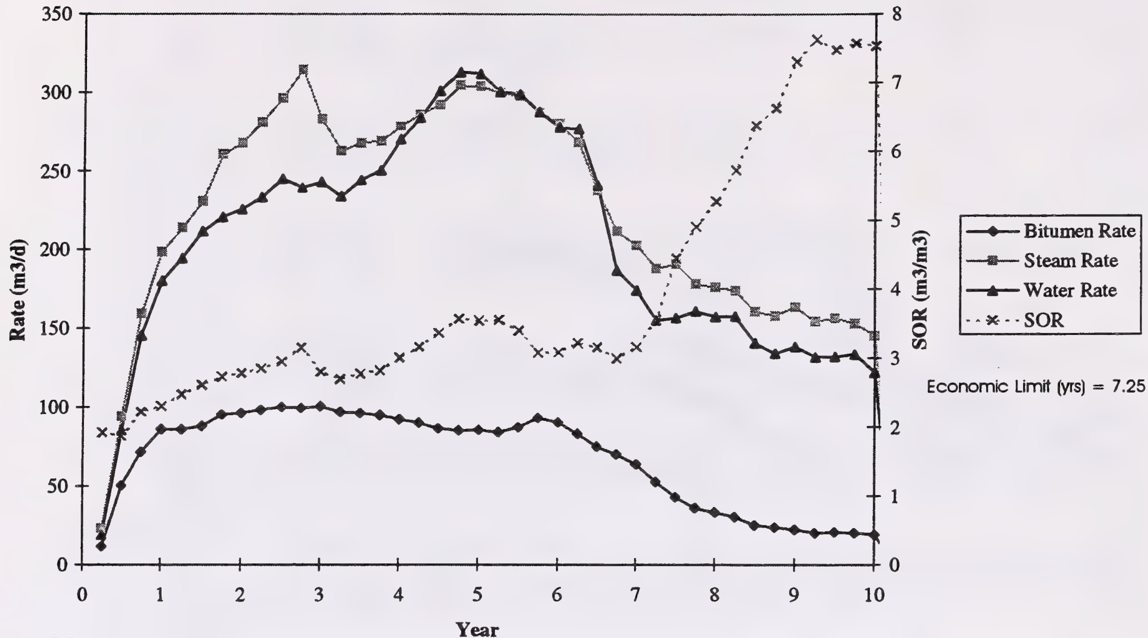


Figure 5.2

AVERAGE WELL PROFILE FROM SIMULATION RESULTS

Athabasca McMurray - 5 m Water Sands at 550 kPa

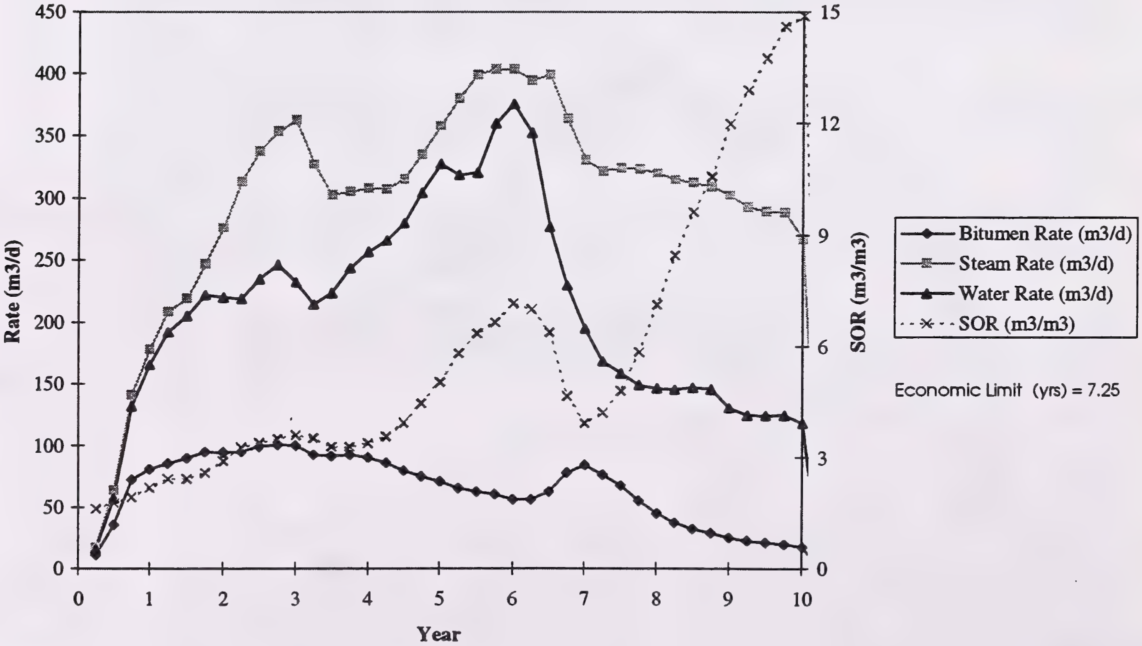


Economic Limit (yrs) = 7.25

Figure 5.3

AVERAGE WELL PROFILE FROM SIMULATION RESULTS

Athabasca McMurray - 5 m Gas Cap & 5 m Water Sands at 1800 kPa



Economic Limit (yrs) = 7.25

Figure 5.4

AVERAGE WELL PROFILE FROM SIMULATION RESULTS

Athabasca McMurray - 5 m Gas Cap & 5 m Water Sands at 550 kPa

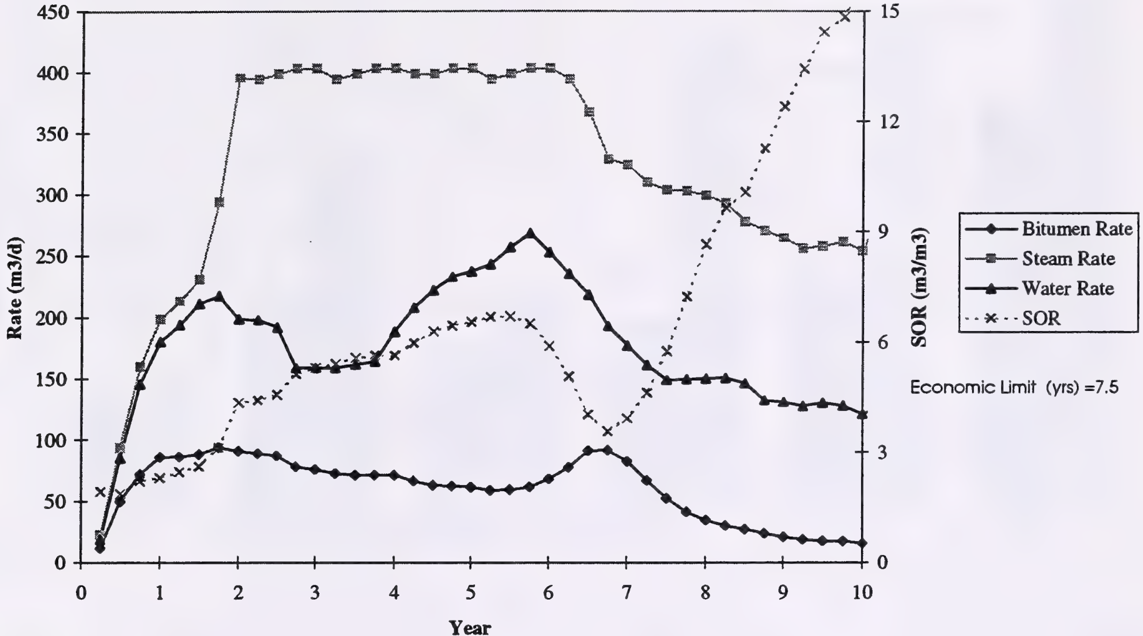


Figure 5.5

AVERAGE WELL PROFILE FROM SIMULATION RESULTS

Athabasca McMurray - 10 m Water Sands at 1800 kPa

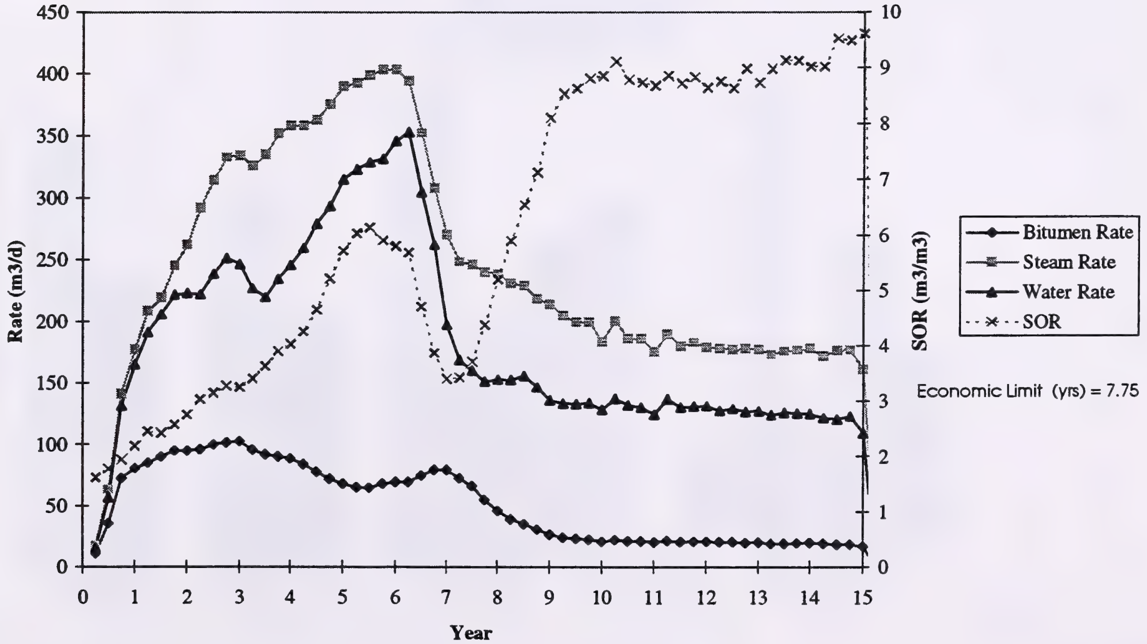


Figure 5.6

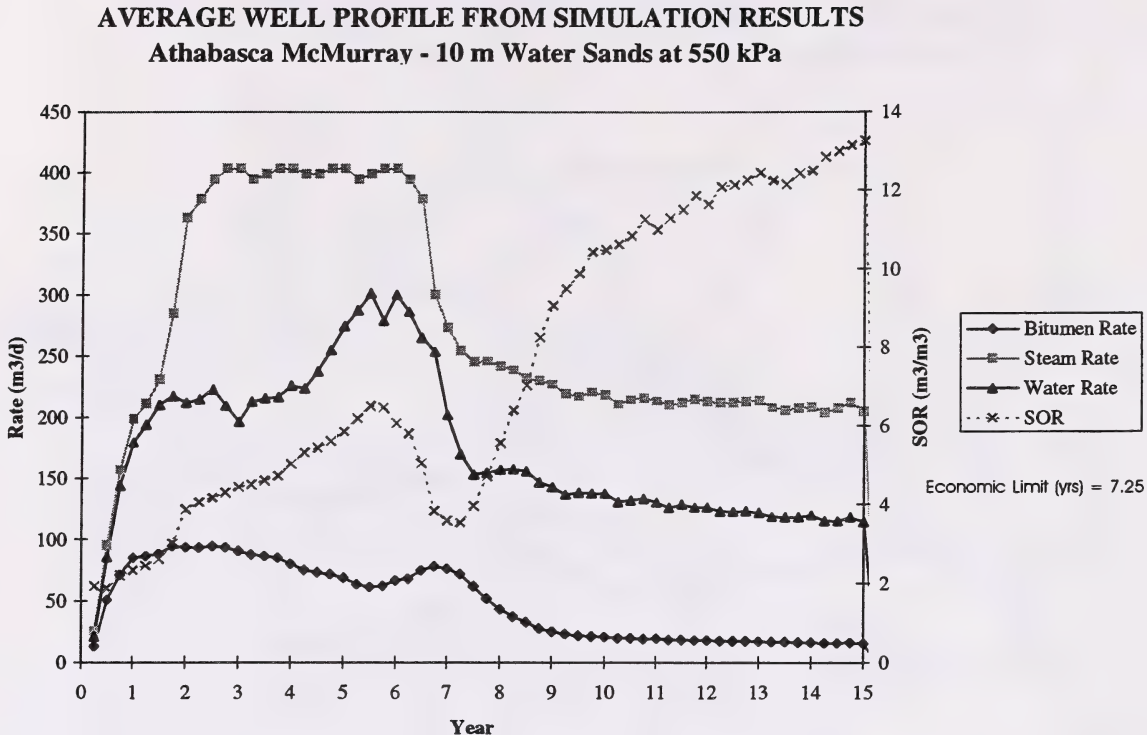


Figure 5.7

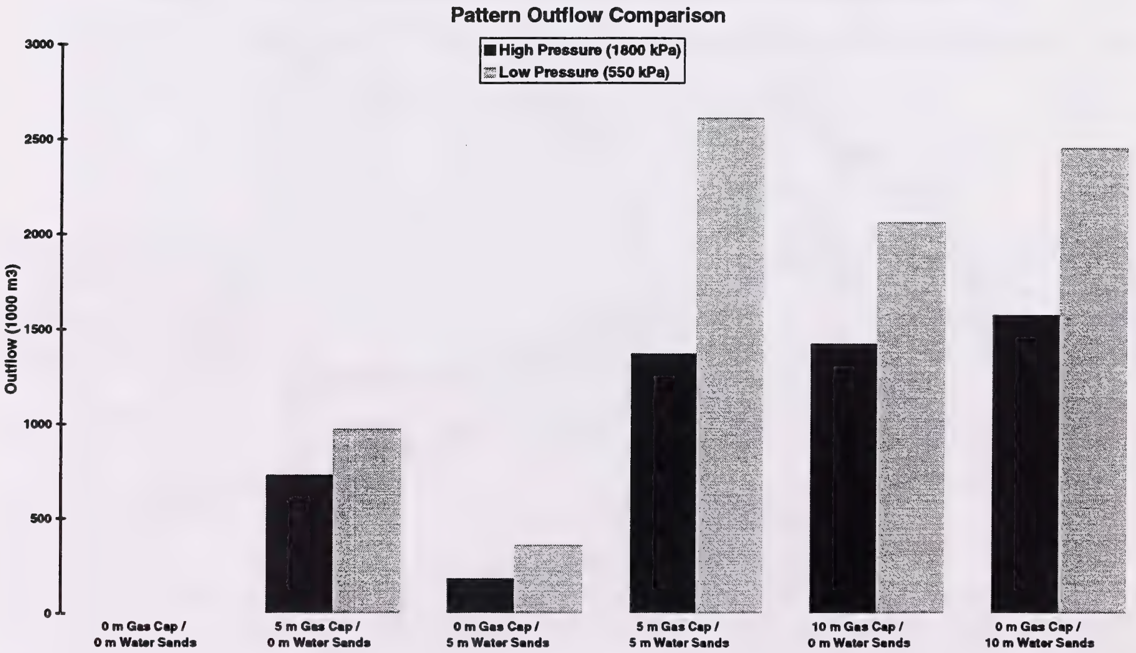


Figure 5.8a

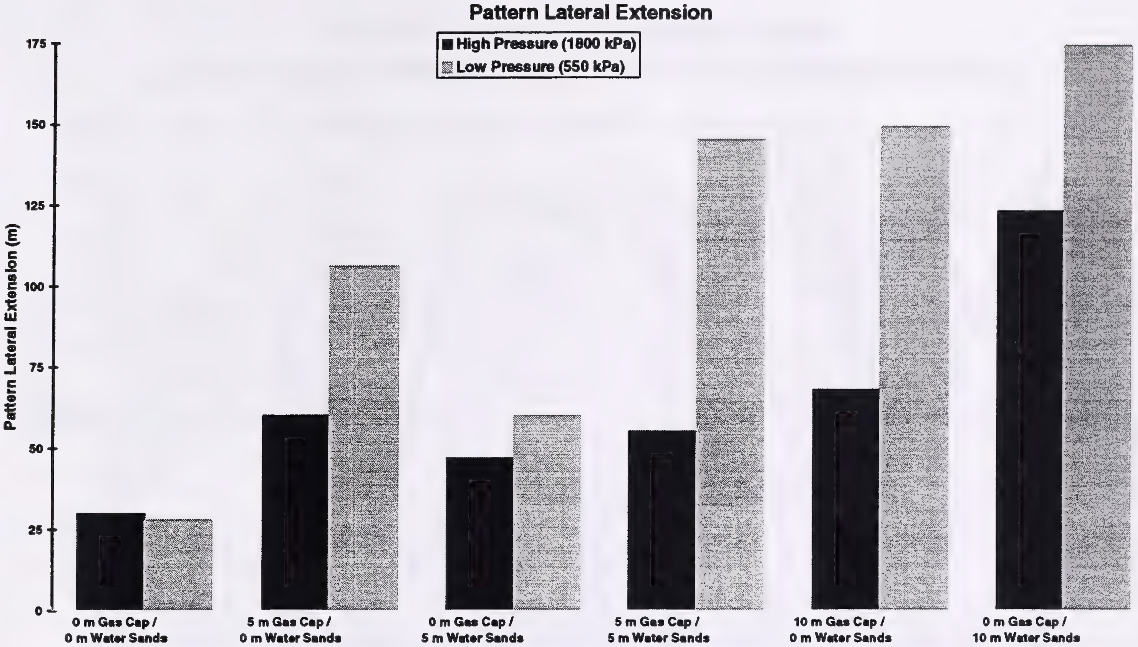


Figure 5.8b

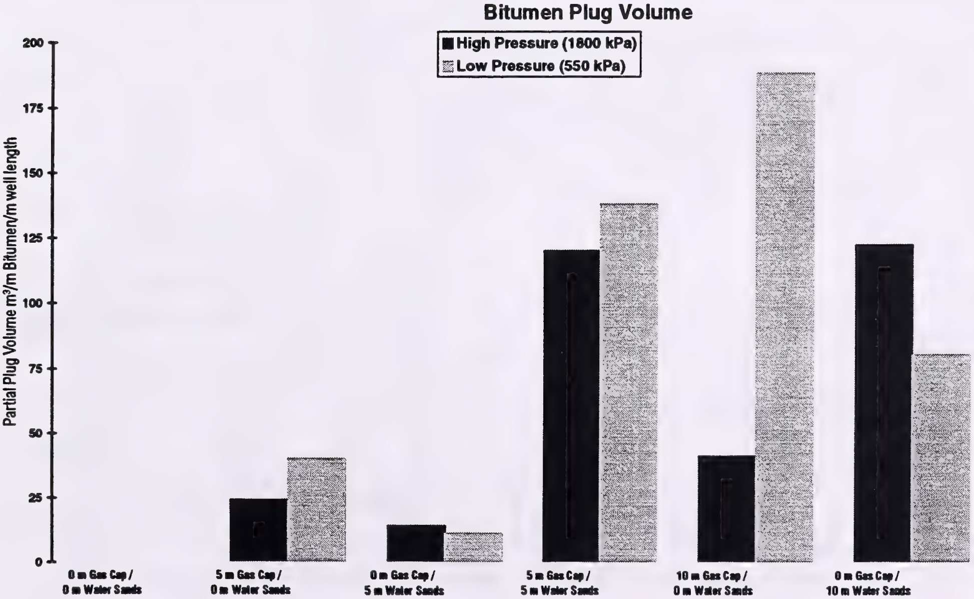
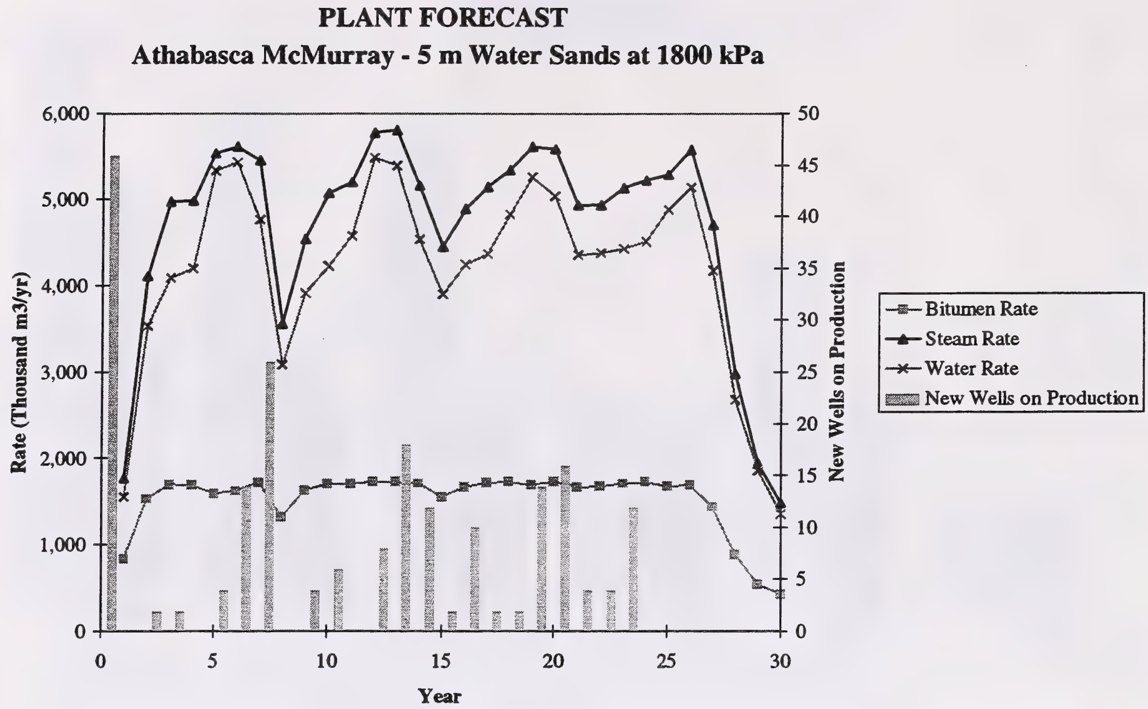
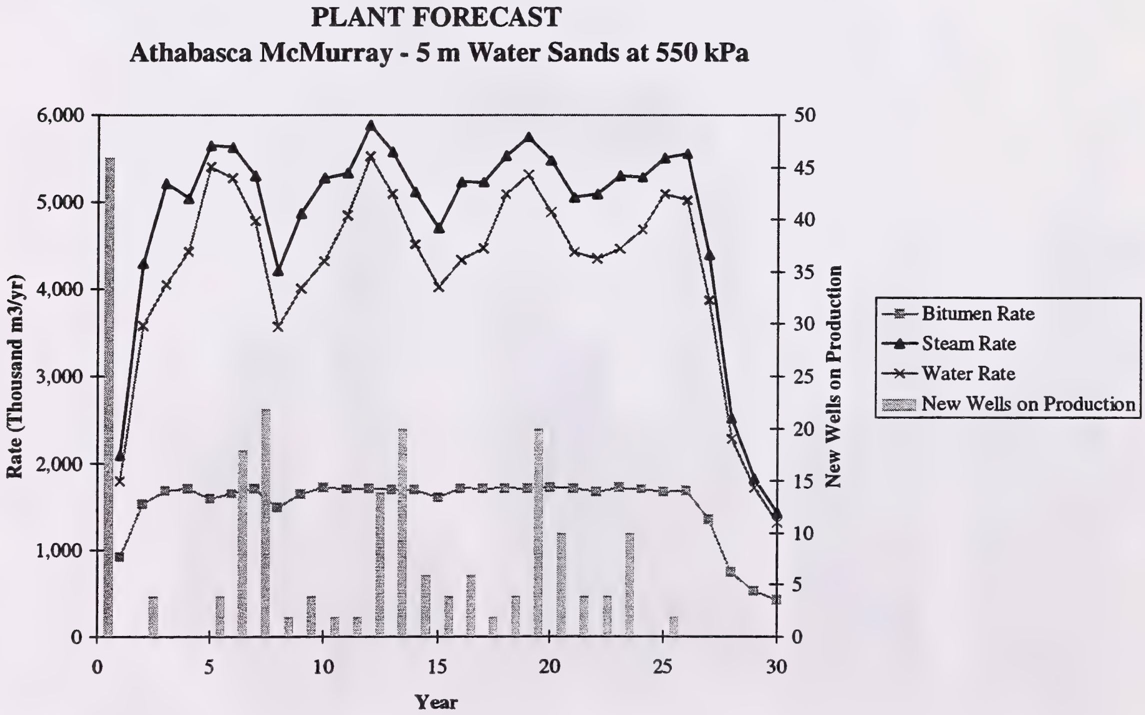


Figure 5.8c



PLANT FORECAST
Athabasca McMurray - 5 m Water Sands at 1800 kPa

Figure 5.9



PLANT FORECAST
Athabasca McMurray - 5 m Water Sands at 550 kPa

Figure 5.10

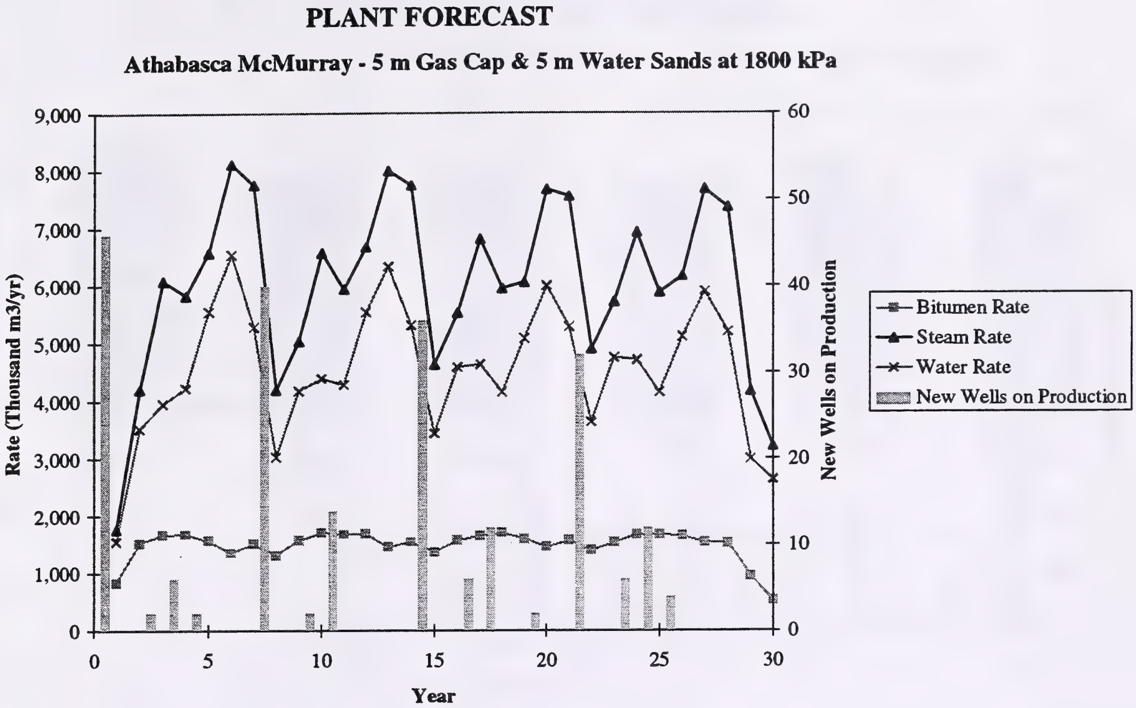


Figure 5.11

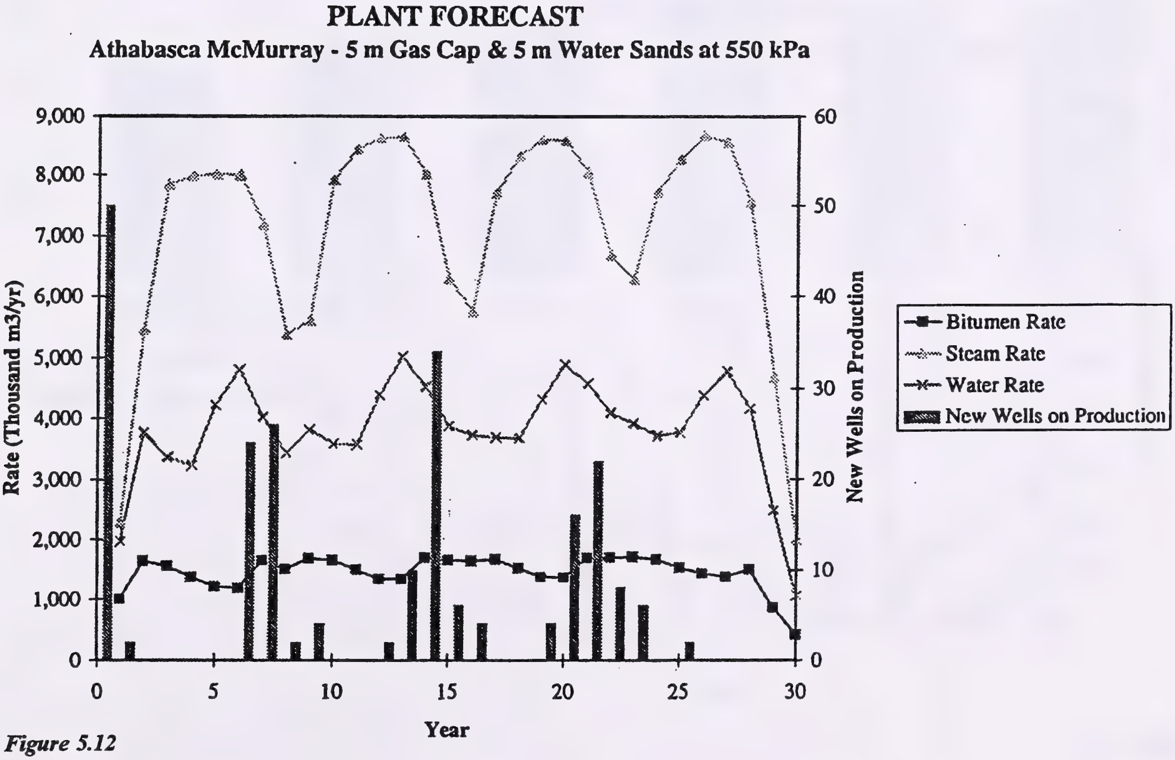


Figure 5.12

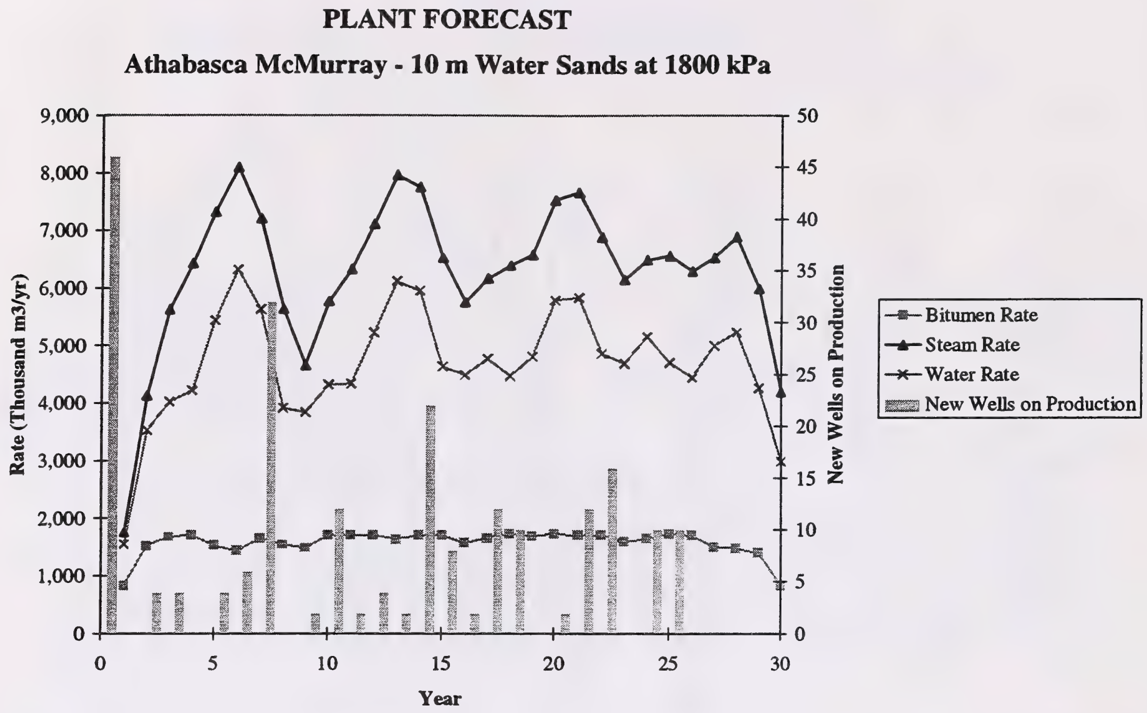


Figure 5.13

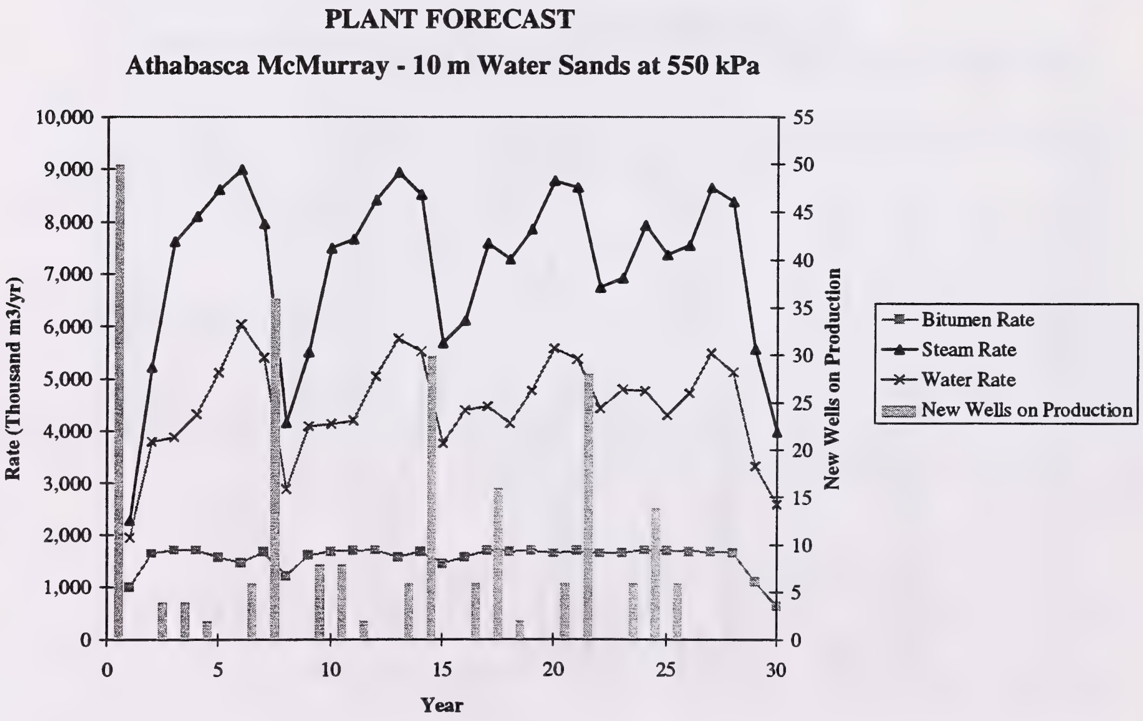


Figure 5.14

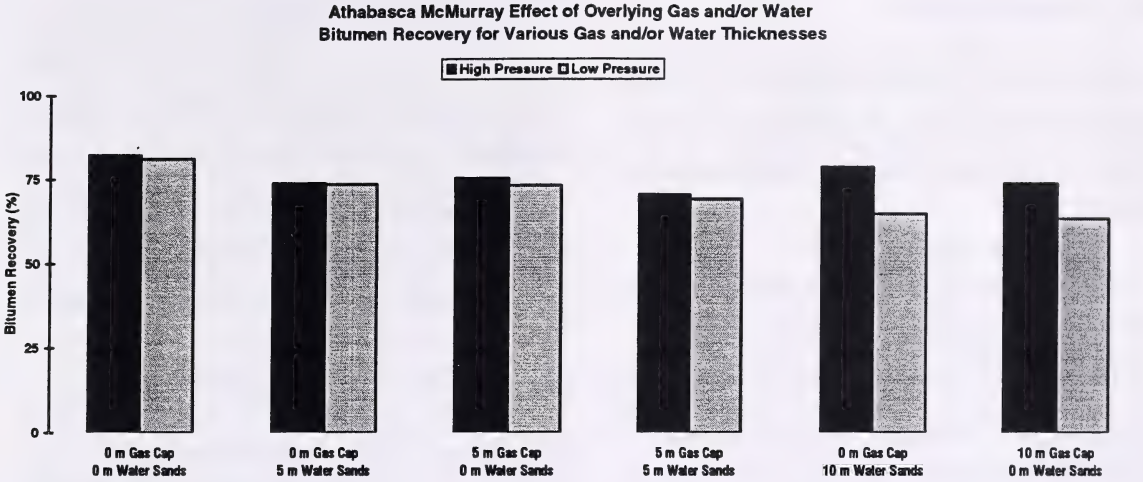


Figure 5.15

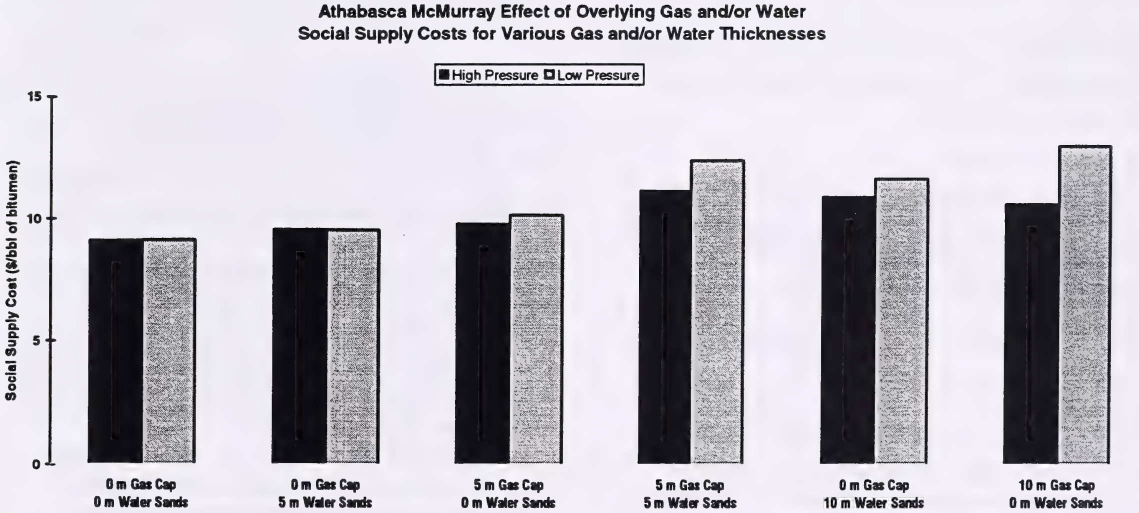


Figure 5.16

6.0 Sensitivities

Sensitivities of supply cost to a number of factors including pattern life, gas cost and a discount factor and of a cumulative steam oil ratio to other general reservoir parameters were analyzed. The results of these analyses are presented in this section and shown as spider diagrams on Figures 6.1 and 6.2.

6.1 Pattern Life

To test the sensitivity of the pattern life, four runs were completed using the Athabasca McMurray base case (no gas cap) with the pattern lives of 4, 6, 8 and 10 years. The results are provided in Table 6.1 and show that if the pattern life is reduced too much, the supply price begins to increase (as shown in the 4-year case) due to less than optimum use of well drilling investment. The bitumen recovery is also reduced since the pattern would be abandoned at a higher bitumen production rate. The social supply cost for the 6 and 8-year pattern life cases are similar, $9.17/bbl and $9.15/bbl, respectively. The recovery, however, is lower for the 6-year life (68% as compared to 81%). This suggests that the production gained from the additional two years justifies the additional cost associated with the larger steam facilities and higher gas consumption in the 8-year pattern life as compared with the 6-year case.

6.2 Gas Price

The gas cost was varied from $2.75/GJ to $1.65/GJ ($2.20/GJ ± 25%) for the Athabasca McMurray 10m gas cap depleted case. The results are provided in Table 6.2. The decrease in gas cost ($1.65/GJ) case did not affect the bitumen recovery as compared to the base case, however, it did lower the supply cost by $1.04/bbl. The pattern life was 7.25 and 7.5 years for the $2.20/GJ and the $1.65/GJ cases, respectively. When the gas cost was increased to $2.75/GJ the pattern life was reduced from 7.25 to 2.75 as compared with the $2.20/GJ case. The reduction in pattern life increased the supply cost from $12.99/bbl to $13.44/bbl and lowered the pattern bitumen recovery from 63.4 to 25.5 %. The large drop in recovery increased the number of well pairs needed to supply the plant from 248 to 658. The 10m gas cap depleted case chosen for this analysis had a relatively high CSOR and gas consumption. The higher gas cost would show less effect on bitumen recovery (pattern life) and social supply cost for other cases with lower gas consumption. A summary of the undiscounted costs (1995 dollars) is provided in Table 6.3 and 6.4 on a year-by-year basis for the $2.20/GJ and $2.75/GJ cases.

6.3 Discount Factor

The social supply cost used for comparing alternatives represents the cost per unit of production over the project life that will provide a rate of return implied by the discount rate before taxes and royalties. A discount rate of 10% is assumed for comparison purposes. To test the supply cost sensitivity to the discount rate, two additional economic runs were completed at 15% and 20%. These discount rates of 15% and 20% significantly increased the social supply cost by 19.8% and 41.9%, respectively from the base case and are shown on Table 6.5. The discount rate only affected the supply price and not the recovery.

6.4 Other Reservoir Parameters

A study conducted by the Alberta Oil Sands Technology and Research Authority in 1992 investigated the sensitivity of the SAGD performance to various parameters. The results of the study are summarized in a report, "Extending the SAGD Process to Other Reservoir Types — Sensitivity Study," by G. Yang, B.I. Nzekwu and W.K. Good dated October 1992 (appendix 4). The study was based on numerical simulation predictions using homogeneous reservoir descriptions, except those cases where shale layers were purposely included. The effect of a number of parameters, including, formation thickness, horizontal and vertical permeability, oil saturation, wettability, tight layers, bottom water and viscosity were considered. The results are summarized on Table 6.6 and the effects on a cumulative steam oil ratio shown for some of the parameters in Figure 6.2.

Although a direct comparison between the 1992 and current study is not possible because of homogeneous conditions, smaller well spacing and different operating pressure in the 1992 study the general trends are of interest and similar. From a sensitivity perspective, major conclusions from the 1992 study include:

1. In high permeability reservoirs, the oil rate is mainly a function of the gravity drainage height or formation thickness. A 40-metre thick formation, for example, produced almost twice as much as a 20-metre thick formation. In low permeability reservoirs, however, the extra thickness does not generate higher rates as expected.
2. In high permeability reservoirs, changing the spacing between injection and production wells, or the injection location in the reservoir, only affected the start-up time. No advantages are achieved by injecting high in a high permeability formation. In low permeability reservoirs, however, oil rates are improved significantly by increased spacing between injection and production wells.

3. Vertical permeabilities mainly controlled the oil production rates, but their effects on steam to oil ratios are relatively small.
4. Higher initial water saturation in the formation result in higher steam to oil ratios, mainly due to less oil production. Some initial mobile water in the formation accelerated the start-up, but also consumed an excessive amount of steam, due to more water production. This excessive steam injection does not produce more oil.
5. Oil-wet formations are favorable candidates for SAGD processes. This is different from most conventional driving processes, such as a water flood, etc.
6. Some non permeable tight streaks of limited areal extent do little damage to the cumulative performance, although they affect some early instantaneous rates. When the steam chamber passed around the streaks, the effects of the streaks are no longer observable.
7. Among layered formations, when the higher permeability is the lower layer, the process performs the best. Placing both wells in this high permeability lower layer allows an earlier start-up and a faster steam chamber growth rate. Well arrangements are extremely critical in a layered formation.
8. Oil viscosity does not play a significant role in SAGD processes. Both lighter heavy oil and more viscous oil sands tend to have very similar behaviors at steam temperatures.
9. Peak oil rate is achieved when steam chamber reaches formation top. The additional amount of the peak rate above its subsequent stable drainage rate depends on the formation permeabilities. In practice, because of the variation of well separation along the well pair, and effect of heterogeneity, different steam chambers reach the top of the formation at different points and at different times. Thus, one peak rate may not be discernible.

Table 6.1

Athabasca McMurray
Pattern Life Sensitivity for the Low Pressure Base Case (0m Depleted Gas Cap)

Pattern Life (years)	4		6		8		10	
Cost Centre	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**
Capital Cost								
Drilling	$ 15.02	24.5%	$ 12.01	20.8%	$ 11.13	19.4%	$ 11.09	18.8%
Seism/Delin/Eng	$ 0.33	0.5%	$ 0.33	0.6%	$ 0.32	0.5%	$ 0.32	0.5%
Steam Facilities	$ 4.40	7.2%	$ 4.30	7.5%	$ 4.76	8.3%	$ 4.93	8.4%
Other Facilities	$ 13.35	21.8%	$ 12.97	22.5%	$ 12.60	21.9%	$ 12.70	21.5%
Total Capital	$ 33.11	54.1%	$ 29.61	51.3%	$ 28.81	50.1%	$ 29.04	49.2%
Operating Cost								
Gas Cost	$ 14.97	24.4%	$ 15.07	26.1%	$ 15.69	27.3%	$ 16.56	28.1%
Utilities	$ 4.02	6.6%	$ 4.04	7.0%	$ 4.20	7.3%	$ 4.43	7.5%
Production Treating	$ 0.79	1.3%	$ 0.78	1.4%	$ 0.78	1.4%	$ 0.78	1.3%
Water Treating	$ 1.11	1.8%	$ 1.14	2.0%	$ 1.20	2.1%	$ 1.27	2.2%
Fixed and Other	$ 7.25	11.8%	$ 7.04	12.2%	$ 6.84	11.9%	$ 6.90	11.7%
Total Operating Cost	$ 28.14	45.9%	$ 28.08	48.7%	$ 28.71	49.9%	$ 29.94	50.8%
Total Cost/m^3 BIT	$ 61.25	100.0%	$ 57.69	100.0%	$ 57.52	100.0%	$ 58.98	100.0%
Total Cost/bbl BIT	$ 9.74		$ 9.17		$ 9.15		$ 9.38	
Plant Summary								
Cum Bitumen Produced (E^3m^3)	45,681		47,020		46,754		47,138	
Cum Steam Injected (E^3m^3)	122,791		127,008		133,320		145,164	
Cum Water Produced (E^3m^3)	108,752		115,692		122,936		134,002	
Plant CDOR (m^3/d)	4,172		4,294		4,270		4,305	
Plant CSOR (m^3/m^3)	2.69		2.70		2.85		3.08	
Number of wells	358		242		202		194	
Avg. Well Summary								
Pattern Life (yrs)	4		6		8		10	
Cum Bitumen Produced (E^3m^3)	128.4		197.1		233.5		248.1	
Cum Steam Injected (E^3m^3)	328.1		505.6		634.5		736.2	
Cum Water Produced (E^3m^3)	306.0		485.2		616.2		715.9	
Well CDOR (m^3/d)	87.9		90.0		80.0		68.0	
Well CSOR (m^3/m^3)	2.56		2.57		2.72		2.97	
Recovery (90m spacing)	45%		68%		81%		86%	

Table 6.2

Athabasca McMurray
Gas Cost Sensitivity for a 10m Depleted Gas Cap

Gas cost ($/GJ)	2.2		2.75		1.65	
Cost Centre	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**
Capital Cost						
Drilling	$ 13.20	16.2%	$ 23.82	28.2%	$ 13.26	17.6%
Seism/Delin/Eng	$ 0.33	0.4%	$ 0.32	0.4%	$ 0.34	0.4%
Steam Facilities	$ 9.06	11.1%	$ 6.82	8.1%	$ 9.18	12.2%
Other Facilities	$ 13.35	16.3%	$ 12.58	14.9%	$ 13.41	17.8%
Total Capital	$ 35.95	44.0%	$ 43.54	51.5%	$ 36.18	48.2%
Operating Cost						
Gas Cost	$ 28.88	35.3%	$ 26.68	31.6%	$ 21.92	29.2%
Utilities	$ 7.72	9.4%	$ 5.75	6.8%	$ 7.83	10.4%
Production Treating	$ 0.79	1.0%	$ 0.78	0.9%	$ 0.79	1.0%
Water Treating	$ 1.13	1.4%	$ 0.98	1.2%	$ 1.14	1.5%
Fixed and Other	$ 7.25	8.9%	$ 6.83	8.1%	$ 7.28	9.7%
Total Operating Cost	$ 45.77	56.0%	$ 41.02	48.5%	$ 38.96	51.8%
Total Cost/m^3 BIT	$ 81.72	100.0%	$ 84.56	100.0%	$ 75.14	100.0%
Total Cost/bbl BIT	$ 12.99		$ 13.44		$ 11.95	
Plant Summary						
Cum Bitumen Produced (E^3m^3)	44944		48998		45624	
Cum Steam Injected (E^3m^3)	241894		190088		249476	
Cum Water Produced (E^3m^3)	110993		102539		113870	
Plant CDOR (m^3/d)	4104		4475		4167	
Plant CSOR (m^3/m^3)	5.38		3.88		5.47	
Number of wells	248		688		248	
Avg. Well Summary						
Pattern Life (yrs)	7.25		2.75		7.5	
Cum Bitumen Produced (E^3m^3)	181		73		185	
Cum Steam Injected (E^3m^3)	928		271		964	
Cum Water Produced (E^3m^3)	448		153		463	
Well CDOR (m^3/d)	69		73		68	
Well CSOR (m^3/m^3)	5.12		3.71		5.21	
Recovery (90m spacing)	63.4%		25.5%		64.8%	

Table 6.3

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 10 m Depleted Gas Cap - Gas Cost of $2.20/GJ

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m³/d)	Steam Injection (m³/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$159	$235	$394						
1997	18			$24,300	$216	$319	$24,835						
1998	18			$24,300	$53,002	$78,072	$155,374						
1999	16			$21,600	$54,367	$80,082	$156,048						
2000	9	2,982	6,780	$12,150	$14,456	$21,293	$47,899	$13,872	$3,737	$909	$997	$10,850	$30,365
2001	9	4,544	17,685	$12,150			$12,150	$36,181	$9,747	$1,284	$1,734	$10,850	$59,796
2002	9	4,114	22,903	$12,150			$12,150	$46,859	$12,623	$1,181	$1,434	$10,850	$72,947
2003	9	3,692	23,578	$12,150			$12,150	$48,240	$12,995	$1,079	$1,465	$10,850	$74,630
2004	9	3,373	23,639	$12,150			$12,150	$48,364	$13,029	$1,003	$1,984	$10,850	$75,229
2005	9	3,614	23,584	$12,150			$12,150	$48,250	$12,998	$1,061	$1,898	$10,850	$75,057
2006	9	4,694	24,336	$12,150			$12,150	$49,789	$13,413	$1,319	$1,833	$10,850	$77,205
2007	9	4,090	14,685	$12,150			$12,150	$30,045	$8,094	$1,175	$1,565	$10,850	$51,729
2008	9	4,732	19,364	$12,150			$12,150	$39,617	$10,672	$1,329	$1,774	$10,850	$64,243
2009	9	4,597	24,299	$12,150			$12,150	$49,714	$13,392	$1,296	$1,645	$10,850	$76,898
2010	9	4,329	26,618	$12,150			$12,150	$54,458	$14,670	$1,232	$1,781	$10,850	$82,992
2011	9	3,942	26,984	$12,150			$12,150	$55,208	$14,872	$1,139	$2,128	$10,850	$84,198
2012	9	4,270	26,959	$12,150			$12,150	$55,156	$14,858	$1,218	$2,107	$10,850	$84,190
2013	9	4,613	25,546	$12,150			$12,150	$52,266	$14,080	$1,300	$1,959	$10,850	$80,455
2014	9	4,531	17,733	$12,150			$12,150	$36,281	$9,774	$1,280	$1,776	$10,850	$59,961
2015	9	4,670	20,429	$12,150			$12,150	$41,797	$11,260	$1,314	$1,771	$10,850	$66,991
2016	9	4,635	23,096	$12,150			$12,150	$47,254	$12,730	$1,305	$1,653	$10,850	$73,792
2017	9	4,490	26,340	$12,150			$12,150	$53,891	$14,517	$1,271	$1,850	$10,850	$82,379
2018	9	3,965	26,961	$12,150			$12,150	$55,161	$14,860	$1,145	$2,046	$10,850	$84,061
2019	9	4,333	26,966	$12,150			$12,150	$55,170	$14,862	$1,233	$2,060	$10,850	$84,176
2020	9	4,687	26,618	$12,150			$12,150	$54,458	$14,670	$1,318	$2,112	$10,850	$83,408
2021	7	4,433	18,219	$9,450			$9,450	$37,276	$10,042	$1,257	$1,764	$10,850	$61,189
2022	0	4,653	21,452	$0			$0	$43,889	$11,823	$1,310	$1,747	$10,850	$69,619
2023	0	4,616	21,530	$0			$0	$44,049	$11,866	$1,301	$1,691	$10,850	$69,757
2024	0	4,581	26,180	$0			$0	$53,563	$14,429	$1,292	$1,887	$10,850	$82,022
2025	0	4,026	26,968	$0			$0	$55,175	$14,863	$1,159	$1,966	$10,850	$84,014
2026	0	4,354	26,968	$0			$0	$55,175	$14,863	$1,238	$2,024	$10,850	$84,151
2027	0	3,763	23,796	$0			$0	$48,685	$13,115	$1,096	$1,864	$10,850	$75,610
2028	0	2,380	14,085	$0			$0	$28,817	$7,763	$765	$1,055	$10,850	$49,250
2029	0	1,431	8,421	$0			$0	$17,229	$4,641	$538	$597	$23,250	$46,255
Totals	248	44,943,776	241,894,207	$334,800	$122,201	$180,000	$637,001	$1,355,890	$365,260	$35,349	$52,170	$337,900	$2,146,569

Table 6.4

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 10 m Depleted Gas Cap - Gas Cost of $2.75/GJ

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m³/d)	Steam Injection (m³/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$127	$235	$362						
1997	18			$24,300	$173	$319	$24,791						
1998	18			$24,300	$42,335	$78,072	$144,706						
1999	16			$21,600	$43,425	$80,082	$145,106						
2000	9	2,982	6,780	$12,150	$11,546	$21,293	$44,990	$17,340	$3,737	$909	$997	$10,850	$33,833
2001	45	4,544	17,685	$60,750			$60,750	$45,227	$9,747	$1,284	$1,734	$10,850	$68,841
2002	9	4,127	19,102	$12,150			$12,150	$48,851	$10,528	$1,184	$1,413	$10,850	$72,826
2003	9	4,349	12,728	$12,150			$12,150	$32,550	$7,015	$1,237	$1,583	$10,850	$53,235
2004	36	4,722	21,553	$48,600			$48,600	$55,121	$11,879	$1,326	$1,744	$10,850	$80,920
2005	12	4,267	14,996	$16,200			$16,200	$38,352	$8,265	$1,217	$1,454	$10,850	$60,139
2006	42	4,575	17,807	$56,700			$58,700	$45,539	$9,814	$1,291	$1,707	$10,850	$69,201
2007	10	4,588	19,133	$13,500			$13,500	$8,632	$10,545	$1,289	$1,583	$10,850	$73,198
2008	26	4,649	15,661	$35,100			$35,100	$11,577	$8,632	$1,309	$1,717	$10,850	$62,558
2009	20	4,662	21,006	$27,000			$27,000	$53,721	$11,577	$1,312	$1,677	$10,850	$79,137
2010	14	4,528	15,498	$18,900			$18,900	$39,636	$8,542	$1,280	$1,589	$10,850	$61,897
2011	40	4,674	19,625	$54,000			$54,000	$50,190	$10,816	$1,315	$1,725	$10,850	$74,895
2012	10	4,340	17,162	$13,500			$13,500	$43,890	$9,459	$1,235	$1,490	$10,850	$66,924
2013	36	4,658	16,832	$46,600			$48,600	$43,047	$9,277	$1,311	$1,729	$10,850	$66,214
2014	12	4,453	19,146	$16,200			$16,200	$48,964	$10,552	$1,262	$1,593	$10,850	$73,221
2015	20	4,515	15,841	$27,000			$27,000	$40,513	$8,731	$1,277	$1,604	$10,850	$62,974
2016	34	4,609	19,092	$45,900			$45,900	$48,827	$10,523	$1,299	$1,684	$10,850	$73,183
2017	22	4,583	17,693	$29,700			$29,700	$45,249	$9,752	$1,293	$1,590	$10,850	$68,734
2018	32	4,679	18,170	$43,200			$43,200	$46,469	$10,015	$1,316	$1,725	$10,850	$70,374
2019	9	4,562	19,057	$12,150			$12,150	$48,736	$10,503	$1,288	$1,621	$10,850	$72,998
2020	19	4,491	15,485	$25,650			$25,650	$39,549	$8,523	$1,271	$1,635	$10,850	$61,828
2021	30	4,626	19,411	$40,500			$40,500	$49,642	$10,698	$1,303	$1,664	$10,850	$74,158
2022	26	4,419	16,832	$35,100			$35,100	$43,046	$9,277	$1,254	$1,543	$10,850	$65,969
2023	14	4,652	18,589	$18,900			$18,900	$47,539	$10,245	$1,310	$1,695	$10,850	$71,638
2024	16	4,592	18,236	$21,600			$21,600	$46,638	$10,051	$1,295	$1,646	$10,850	$70,481
2025	28	4,237	15,553	$37,800			$37,800	$39,774	$8,572	$1,210	$1,544	$10,850	$61,950
2026	0	4,590	18,251	$35,100			$35,100	$46,675	$10,059	$1,295	$1,631	$10,850	$70,509
2027	0	4,592	17,999	$0			$0	$46,031	$9,920	$1,295	$1,635	$10,850	$69,731
2028	0	4,545	18,289	$0			$0	$46,773	$10,080	$1,284	$1,641	$10,850	$70,628
2029	0	4,449	17,598	$0			$0	$45,006	$9,699	$1,261	$1,605	$43,750	$101,321
Totals	632	134,259	520,810	$886,300	$97,606	$180,001	$1,167,905	$1,263,104	$287,033	$38,012	$48,198	$358,400	$2,063,515

Table 6.5

Athabasca McMurray
Discount Factor Sensitivity for the Low Pressure Base Case (0m Depleted Gas Cap)

Discount Factor (%)	10		15		20	
Cost Centre	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**	**Supply Cost**	**Cost Share (%)**
Capital Cost						
Drilling	$ 11.13	19.4%	$ 14.07	20.4%	$ 17.24	21.1%
Seism/Delin/Eng	$ 0.32	0.5%	$ 0.50	0.7%	$ 0.74	0.9%
Steam Facilities	$ 4.76	8.3%	$ 7.04	10.2%	$ 9.60	11.8%
Other Facilities	$ 12.60	21.9%	$ 18.61	27.0%	$ 25.39	31.1%
Total Capital	$ 28.81	50.1%	$ 40.22	58.4%	$ 52.95	64.9%
Operating Cost						
Gas Cost	$ 15.69	27.3%	$ 15.56	22.6%	$ 15.45	18.9%
Utilities	$ 4.20	7.3%	$ 4.18	6.1%	$ 4.15	5.1%
Production Treating	$ 0.78	1.4%	$ 0.78	1.1%	$ 0.78	1.0%
Water Treating	$ 1.20	2.1%	$ 1.19	1.7%	$ 1.18	1.4%
Fixed and Other	$ 6.84	11.9%	$ 6.98	10.1%	$ 7.12	8.7%
Total Operating Cost	$ 28.71	49.9%	$ 28.69	41.6%	$ 28.68	35.1%
Total Cost/m³ BIT	$ 57.52	100%	$ 68.91	1	$ 81.63	1
Total Cost/bbl BIT	$ 9.15		$ 10.96		$ 12.98	
Plant Summary						
Cum Bitumen Produced (E^3m^3)	46754		46754		46754	
Cum Steam Injected (E^3m^3)	133320		133320		133320	
Cum Water Produced (E^3m^3)	122936		122936		122936	
Plant CDOR (m^3/d)	4270		4270		4270	
Plant CSOR (m^3/m^3)	2.9		2.9		2.9	
Number of wells	202		202		202	
Avg. Well Summary						
Pattern Life (yrs)	8		8		8	
Cum Bitumen Produced (E^3m^3)	233.5		233.5		233.5	
Cum Steam Injected (E^3m^3)	634.5		634.5		634.5	
Cum Water Produced (E^3m^3)	616.2		616.2		616.2	
Well CDOR (m^3/d)	80.0		80.0		80.0	
Well CSOR (m^3/m^3)	2.72		2.72		2.72	
Recovery (90m spacing)	81.1%		81.1%		81.1%	

Table 6.6

Summary of Results from 1992 Sensitivity Study

Case	Case Description	Net Pay (m)	Horizontal Permeability (D)	Vertical Permeability (D)	Year	CDOR (m^3/D)	CSOR (m^3/m^3)	Bitumen Recovery (%)
1	base	20	10	5	2.5	165.4	2.25	72
2	thickness change	40	10	5	2.5	338.6	1.79	73
3	low horizontal and vertical permeability	20	1	0.5	2.5	35.8	3.00	15
					4.0	40.3	3.06	28
4	low horizontal and vertical permeability	40	1	0.5	4.0	38.8	3.05	14
					10.0	46.4	3.13	40
5	increased inter-well spacing (10m)	20	10	5	2.5	152.7	2.08	72
					3.0	139.1	2.23	73
6	increased inter-well spacing (10m)	40	1	0.5	10.0	62.2	2.50	54
7	low vertical permeability	20	10	0.5	2.5	56.0	2.63	24
					4.0	60.8	2.74	42
8	low oil saturation (Soi=60%)	20	10	5	1.5	154.0	2.97	57
					2.5	120.8	3.34	74
9	oil wet, Krw=-.95	20	10	5	2.0	233.3	1.92	81
10	water wet, Krw=0.04	20	10	5	2.5	136.9	2.28	60
11	Cold Lake viscosity u=100,000 cp	20	10	5	2.5	172.5	2.29	75
12	layered: upper	10	10	5	2.5	36.1	3.19	15
	lower	10	1	0.5				
13	layered: upper	10	1	0.5	2.5	148.8	2.29	65
	lower	10	10	5				
14	layered: upper	5	1	0.5	2.5	127.5	2.12	56
	middle	10	10	5				
	lower	5	1	0.5				

Unless otherwise noted the following parameters apply:

Operating Steam Chest Pressure = 2700 kPa
Spacing Between Well Pairs = 70m
Porosity = 35%
Well Length = 500m

Krw = 0.45
Viscosity at Initial Conditions = 1,000,000cp (Athabasca)
Inter Well Spacing = 5m
Initial Oil Saturation = 85%

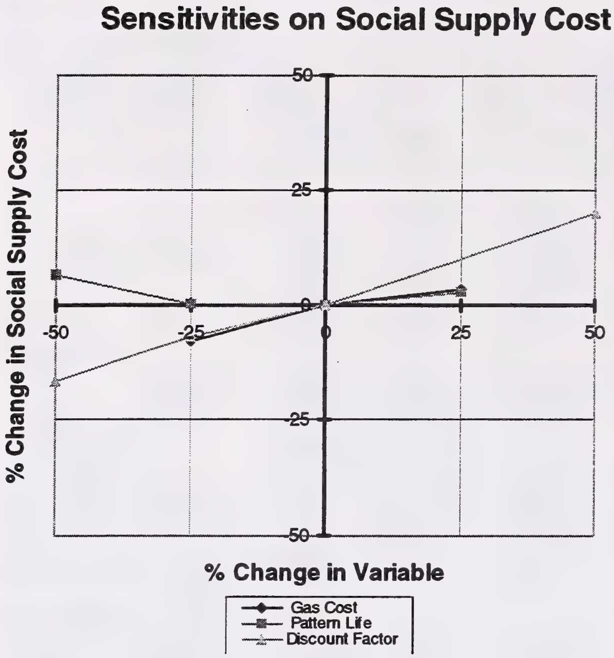


Figure 6.1

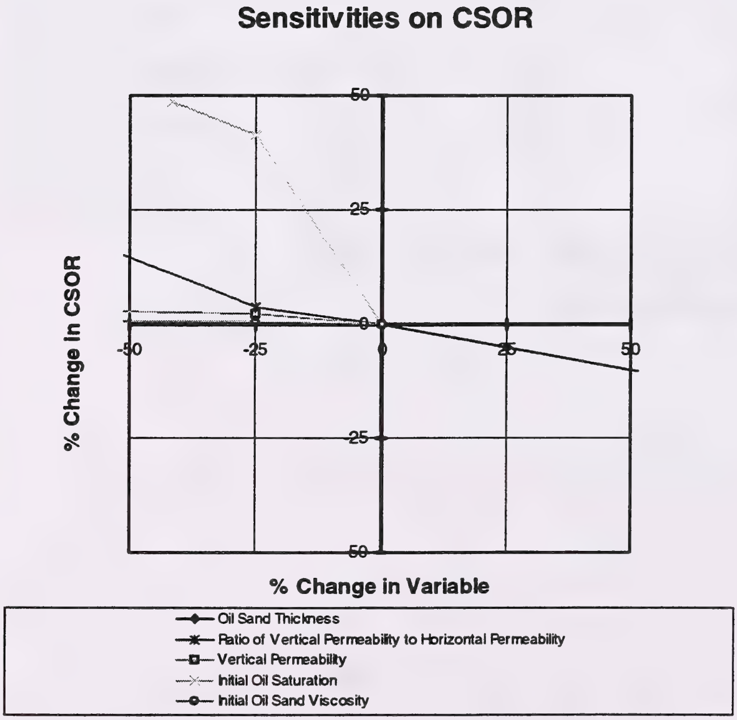


Figure 6.2

Appendix 1

Overburden Considerations, Simulation Data Set and Results, Commercial Plant Utilization and Detailed Plant Bitumen Forecasts and Undiscounted Costs for Athabasca McMurray

Athabasca Wabiskaw-McMurray Overburden Considerations

Maximum operating pressure is one of the issues being addressed as Industry considers applying the SAGD process at shallow depths. The results of a brief literature search and some comments pertaining to this issue are presented in the following discussion.

Pressures at which in-situ processes in the Athabasca area can be operated have been a topic of considerable thought and discussion particularly as it applies to shallow deposits. Some areas with high bitumen saturation over the entire section can be operated at conditions under fracture pressure but considerably above the original reservoir pressure. In areas where higher water saturated sands exist within the oil sand, injection fluid leak-off may occur laterally and negatively impact the economics of recovery processes. Fluid leak-off may occur vertically as well if the overburden is not an effective pressure seal. These conditions will dictate that SAGD be operated at close to the reservoir pressure.

The literature search on the topic of hydrogeology of the Athabasca Oil Sands area identified a number of applicable papers and reports, the most applicable summarized in the following discussion.

Regional Pressures

A technical paper, "Hydrogeology of Formation Waters, Northeastern Alberta Basin" by Stefan Bachu and J.R. Underschultz published in the AAPG Bulletin October 1993, addressed the regional pressure distribution. In the paper the authors show a fresh water hydraulic head contour map based on 1053 drill stem tests conducted in the Athabasca oil sand area.

The department, (ADOE and formerly AOSTRA) has had experience at a number of in-situ process pilots in the area which have been reviewed with respect to original reservoir pressure and found to agree with the interpretation presented by Bachu and Underschultz. Data from these pilots are summarized as follows:

Kearl Lake:

The Husky Kearl Lake steam pilot obtained source water from the base of the McMurray oil sand approximately six miles north of the pilot location. At the source water location the McMurray was slightly lower in elevation and the basal sand was water laden.

Shut-in water levels were measured on the source wells. Test data from well 1-18-96-7 W7M is summarized as follows:

Top of water sand	64.95 mKB
Shut-in water level (March 1, 1981)	8.15 mKB
Estimated KB elevation	339 mASL
∴ Water level (head)	331 mASL

Bachu and Underschultz map shows a hydraulic head contour of 325 mASL in the approximate location of the Kearl Lake project which is in good agreement to data from the pilot.

GLISP:

The Amoco GLISP project located in 5-2-86-7 W4M was also a steam flood pilot. Some of the pertinent details for this location are:

KB elevation	480 mASL
Depth to Top of McMurray sand	190 mKB (291m ASL)
Depth to Base of McMurray sand	230 mKB (250m ASL)

The final report identified the original reservoir pressure as approximately 1100 kPa which represents a hydraulic head of 110m above the oil sand or 360m ASL to 401m ASL depending on whether the top or base of the sand is referenced. Bachu and Underschultz show a hydraulic head of approximately 375m ASL in the GLISP area which is in good agreement with the estimate in the pilot final report.

UTF Project:

The original reservoir pressure for the UTF project located in 3-18-93-12 W4M has been estimated at 550 kPa or a 55m hydraulic head above the sand. Pertinent details for the project are:

G.L. elevation approximately	433 mASL
Depth to Top of McMurray sand	135 mGL (298 mASL)
Depth to Base of McMurray sand	160 mGL (273 mASL)

The hydraulic head of UTF to provide a 550 kPa original reservoir pressure would be 328m ASL to 353m ASL depending on whether the top or base of sand is referenced. Bachu and Underschultz mapping shows approximately 325m ASL to 350m ASL also in good agreement with estimates used in UTF evaluations.

Localized Pressures

The second reference which applies to a more localized potential mining area in Townships 94-97 and Ranges 7 to 11 W4M is a study conducted by Sproule Associates for the Oil Sands Environmental Study Group documented in a report "Regional Hydrogeological Study — McMurray Oil Sands Area, Alberta — Phase I" dated October 1974. The prime issue addressed in the study was the impact of ground water on mining of the McMurray oil sand. The water aquifers primarily in the McMurray but one in the Devonian (Methy) were pump tested at a number of locations by various operators and summarized in the report. These pump tests provided an estimate of water transmissibility and the static hydraulic head at each location.

The results of the pump tests are summarized on Attachment 1. A number of conclusions can be drawn from this data:

1. Many in the Petroleum Industry relate pressure to depth of the deposit which is generally satisfactory for deeper formations. In shallow formations such as at Athabasca, however, the pressure is related to elevation and distance measured from the Athabasca River and other oil sand outcrops and is independent of overburden. It is noted that the elevation of the Athabasca River in this area is in the order of 224m ASL.
2. The Devonian and McMurray hydraulic heads were shown to be very similar in tests at well 10-25-95-10 W4M. This tends to support a concern identified in the study and elsewhere that the Devonian and McMurray are in pressure communication through faults and areas where the Prairie Evaporite has collapsed as depicted in Attachment 2. Salt water from the Methy formation which underlies the Prairie Evaporite may invade the McMurray oil sands if pressure in the McMurray is reduced or fluid may escape from the McMurray if pressure is increased. This may be some local phenomena but should be considered when selecting the operating pressure for recovery processes in the McMurray oil sand.
3. The transmissibilities measured (imperial gallons per day per foot of hydraulic head) show considerable variation and provide an indication of fluid conductivity. As bitumen saturation and clay content increases the transmissibility of the aquifers will decrease. Areas with none or very low transmissibility will behave as isolated sands and pressures above the original reservoir pressure may be possible.
4. The depth of the interval tested was that of water sands assumed in this case to be the base of the oil sand. The data presented on Attachment 1 indicates that the hydraulic head averages 73 metres from what is considered to be the base of the oil sand.

Overburden vs SAGD Operating Strategy:

SAGD steam chamber pressure should be as high as possible but limited by the effectiveness of the formations overlying the McMurray oil sand in resisting vertical fluid movement and in having low oil sand transmissibility such that lateral fluid movement does not occur. In general for the area of concern the data on Attachment 1 suggests an average aquifer pressure of 728 kPa or a hydraulic head of 73 metres at the base of the McMurray oil sand which is independent of overburden thickness provided that overburden plus the oil sand thickness is greater than 73 metres. For a 25-metre thick oil sand, which is probably average, this would equate to 48 metres of overburden. It is reasoned that for less than 73 metres, the hydraulic head at the base of the oil sand would be the thickness of the oil sand and overburden.

Based on the foregoing, the operating strategies suggested for low overburden applications of SAGD are as follows:

Overburden 50 metres or less:

- Maximum operating pressure at top of the oil sand would be the fluid head represented by the depth of overburden.
- This will minimize fluid leak-off because the hydraulic head of the aquifer is never exceeded. Core holes drilled to evaluate the oil sands particularly prevalent in overburdens of less than 50 metres may have been poorly abandoned. The potential for leakage through these holes necessitates a conservative operating pressure particularly after start-up during the SAGD operating phase.

Overburden greater than 50 metres:

- A conservative approach would be to limit the operating pressure at the top of the oil sand during the SAGD operating phase to the aquifer hydraulic head at the depth of the oil sand in question (e.g. 480 kPa for a 25 metre thick oil sand).
- A middle of the road approach would be to limit the operating pressure at the top of the oil sand during the SAGD operating phase to the hydraulic head represented by the thickness of overburden. The drawback of this approach would be fluid (steam) movement upward if the cap rock was not effective. If this were to occur, the operating pressure would need to be reduced.
- A more aggressive approach would be to operate at close to fracture pressure or at about twice the fluid gradient. This would require a high and continuous bitumen saturation in the sand (no water stringers) and an effective cap rock. Note: UTF operates satisfactorily at 2400 to 2600 kPa with overburden of 135m. This represents a gradient of 19 kPa per metre or about twice the fluid gradient.

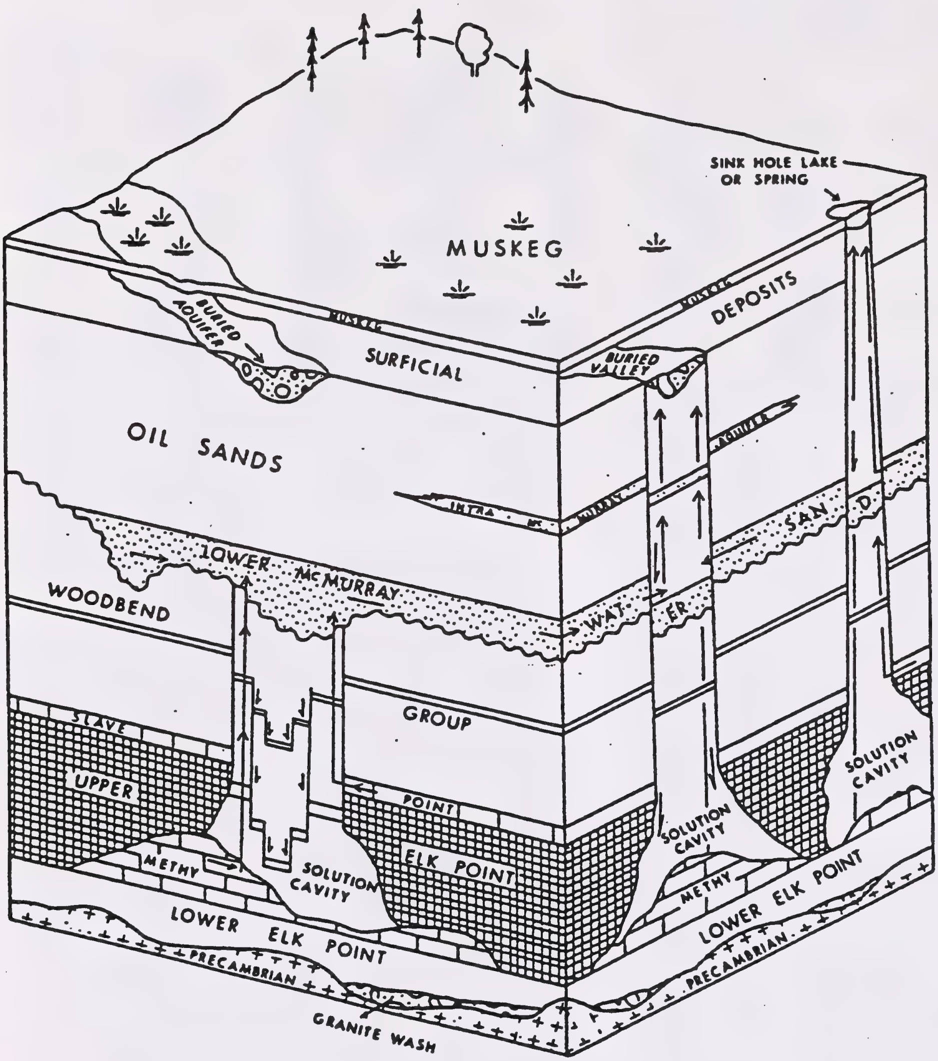
Attachment 1

McMurray & Devonian Aquifers Hydraulic Heads and Transmissibilities

Location	**Zone**	**Surface (m ASL) (1)**	**Test Zone (m ASL) (1)**	**Static Hydraulic Head (m ASL) (1)**	**Aquifer Pressure (kPa)**	**Trans-missibility (igpd/ft) (1)**	**Distance from River (km)**
4-32-94-9 W4M	McMurray	329	237	317	800	250	9.8
10-24-95-9 W4M	Surficial	320	290	318	280	45000	14.8
10-25-95-10 W4M	McMurray	296	207	287	800	7000	7.4
	Devonian	296	84	271	1870	NA	
10-2-96-7 W4M	McMurray	335	259	329	700	17500	32
9-9-96-10 W4M	McMurray	293	182	271	890	10000	5
1-1-96-11 W4M	McMurray	289	183	240	570	1200	0
10-20-97-7 W4M	McMurray	341	265	326	610	18000	25.8
McMurray averages (excluding Devonian)		314	222	295	728		

(1) Data interpreted from Cross-sections
Sproule Study, October 1974
MASL — metres above sea level
igpd/ft — imperial gallons per day per foot

Attachment 2 — Sketch Showing Possible Effects of Salt Solution on Groundwater System (not to scale)



Source: J.C. Sproule and Associates Ltd.

```
** SOURCE DATA SET: ATHABASCA MCMURRAY CASE STUDY - BASE CASE FOR EFFECT OF OVER
BURDEN & NET PAY
** CMG STARS SIMULATION
**
** No Thief Zone (i.e. Gas Cap / Overlying Water Sands)
** 2D run assuming a Dead Oil @ Reservoir Conditions
** Model Dimensions: 45 m x 500 m x 24 m
** 500 m Length Horizontal Wells and 24 m of Pay above the Producer Wells
** Initial Reservoir Pressure = 1400 kPa
** One-Half Well Pair Model / Forecast based on Single Well Pair Basis
** (Well Pair assumes perfect symmetry)
** Inter-Well Distance is 90 m and Injector/Producer Vertical Spacing is 4.5 m
** Grid Block thickness is constant in i-direction (30 - 1.5 m), j-direction
** consists of a single slab of 500 m, and k-direction is also constant ( 16 - 1
.5 m)
** No "Short Circuit Layer" (i.e. 2D Model)
** Injput and Output Units are SI; and time basis is days
**
** -------------  INPUT/OUTPUT  ---------------------

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*title1 'Joint ADOE-EUB SAGD Study'
*title2 'Case Study: Athabasca McMurray (140 m Overburden / 24 m Net Pay)'
*title3 'Pattern Simulation: 1/2 Well Pair Model'

**restart

*maxerror 1
*wrst *time

*prntorien  2  0
*outprn *grid *pres *temp *sw *so *sg *x *y
*outprn *well *brief
*wsrf *grid *time
*outsrf *grid *pres *temp *sw *so *sg *x *y


** ---------  GRID AND RESERVOIR DEFINITION ---------

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*kdir *up

*di *ivar 30*1.5

*dj *jvar 500.

*dk *kvar 16*1.5

*dtop *con 140.0

*por *ijk
1:30  1  1:2     0.35
1:30  1  3       0.35
1:30  1  4       0.35
1:30  1  5       0.30
1:30  1  6:7     0.35
1:30  1  8       0.30
```

```
1:30  1  9:10    0.35
1:30  1  11:16   0.30

*permi *ijk
1:30  1  1:2     10000
1:30  1  3       10000
1:30  1  4       10000
1:30  1  5       2000
1:30  1  6:7     10000
1:30  1  8       2000
1:30  1  9:10    10000
1:30  1  11:16   2000

*permj *ijk
1:30  1  1:2     10000
1:30  1  3       10000
1:30  1  4       10000
1:30  1  5       2000
1:30  1  6:7     10000
1:30  1  8       2000
1:30  1  9:10    10000
1:30  1  11:16   2000

*permk *ijk
1:30  1  1:2     2500
1:30  1  3       2500
1:30  1  4       2500
1:30  1  5       200
1:30  1  6:7     2500
1:30  1  8       200
1:30  1  9:10    2500
1:30  1  11:16   200

*cpor 7.0e-6 *prpor 100.0

*rockcp 2.390e6
*cpo    17.0
*thconr 1.469e5
*thconw 1.469e5
*thcono 1.469e5

*hlossprop *overbur 2.390e6 1.469e5 *hlosst 7.0 *hlosstdiff 0.1
*hlossprop *underbur 2.390e6 2.333e5 *hlosst 7.0 *hlosstdiff 0.1
```

File: Athabasca_Base_Case.dat 1

```
** ============== FLUID DEFINITIONS =================

*model 2 2 2

*compname      'WATER'      'OIL'
**           --------------------------
*cmm             0          0.5
*pcrit           0          0
*tcrit           0          0

*molden          0          2020.0
*cp              0          6.84e-7
*ct1             0          7.85e-4
*ct2             0          0

*kv1             0          0
*kv2             0          0
*kv3             0          0
*kv4             0          0
*kv5             0          0

*cpl1            0          1000.0
*cpg1            0          841.0
*hvapr           0          1346.0

*visctable

**  Temp
    10.0        0          0.17e7
    20.0        0          0.319e6
    40.0        0          0.223e5
    60.0        0          3073.0
    80.0        0           680.6
   100.0        0           212.63
   120.0        0            85.54
   140.0        0            41.57
   160.0        0            23.32
   180.0        0            14.60
   200.0        0             9.96
   220.0        0             7.26
   240.0        0             5.59
   260.0        0             4.49
   280.0        0             3.73
```

```
** =================== ROCK-FLUID DATA ==============

*rockfluid

*rpt 1

*swt

**  Sw        Krw        Krow
** ----------------------------
   0.1500    0.0000     0.9920
   0.2000    0.200e-3   0.9790
   0.2500    0.160e-2   0.9500
   0.3000    0.550e-2   0.7200
   0.3500    0.130e-1   0.6000
   0.4000    0.254e-1   0.4700
   0.4500    0.440e-1   0.3500
   0.5000    0.698e-1   0.2400
   0.5500    0.1040     0.1650
   0.6000    0.1480     0.0930
   0.6500    0.2040     0.0700
   0.7000    0.2710     0.0400
   0.7500    0.3520     0.0150
   0.8000    0.4470     0.0000
   0.8500    0.5590     0.0000
   0.9000    0.6870     0.0000
   0.9500    0.8340     0.0000
   1.0000    1.0000     0.0000

*slt

**  Sl        Krg        Krog
** ----------------------------
   0.1500    1.0000     0.0000
   0.2000    0.9500     0.200e-3
   0.2500    0.8400     0.160e-2
   0.3000    0.7200     0.550e-2
   0.3500    0.6000     0.130e-1
   0.4000    0.4700     0.254e-1
   0.4500    0.3500     0.440e-1
   0.5000    0.2400     0.698e-1
   0.5500    0.1650     0.1040
   0.6000    0.930e-1   0.1480
   0.6500    0.750e-1   0.2040
   0.7000    0.450e-1   0.2710
   0.7500    0.270e-1   0.3520
   0.8000    0.200e-1   0.4470
   0.8500    0.100e-1   0.5590
   0.9000    0.500e-2   0.6870
   0.9500    0.0000     0.8340
   1.0000    0.0000     0.9920
```

File: Athabasca Base Case.dat 2

```
*rpt 2

*swt

**  Sw          Krw         Krow
** -----------------------------
   0.25        0.0         0.95
   0.3         0.0005      0.72
   0.35        0.003       0.6
   0.4         0.009       0.47
   0.45        0.022       0.35
   0.5         0.046       0.24
   0.55        0.081       0.165
   0.6         0.131       0.093
   0.65        0.186       0.07
   0.7         0.257       0.04
   0.75        0.341       0.015
   0.8         0.436       0.
   0.85        0.551       0.
   0.9         0.683       0.
   0.95        0.832       0.
   1.0         1.0         0.

*slt

**  Sl          Krg         Krog
** -----------------------------
   0.25        0.84        0.
   0.3         0.72        0.0005
   0.35        0.6         0.003
   0.4         0.47        0.009
   0.45        0.35        0.022
   0.5         0.24        0.046
   0.55        0.165       0.081
   0.6         0.093       0.131
   0.65        0.075       0.186
   0.7         0.045       0.257
   0.75        0.027       0.341
   0.8         0.02        0.436
   0.85        0.01        0.551
   0.9         0.005       0.683
   0.95        0.          0.832
   1.0         0.          0.95

*krtype *ijk
1:30  1  1:2         1
1:30  1  3           1
1:30  1  4           1
1:30  1  5           2
1:30  1  6:7         1
1:30  1  8           2
1:30  1  9:10        1
1:30  1  11:16       2
```

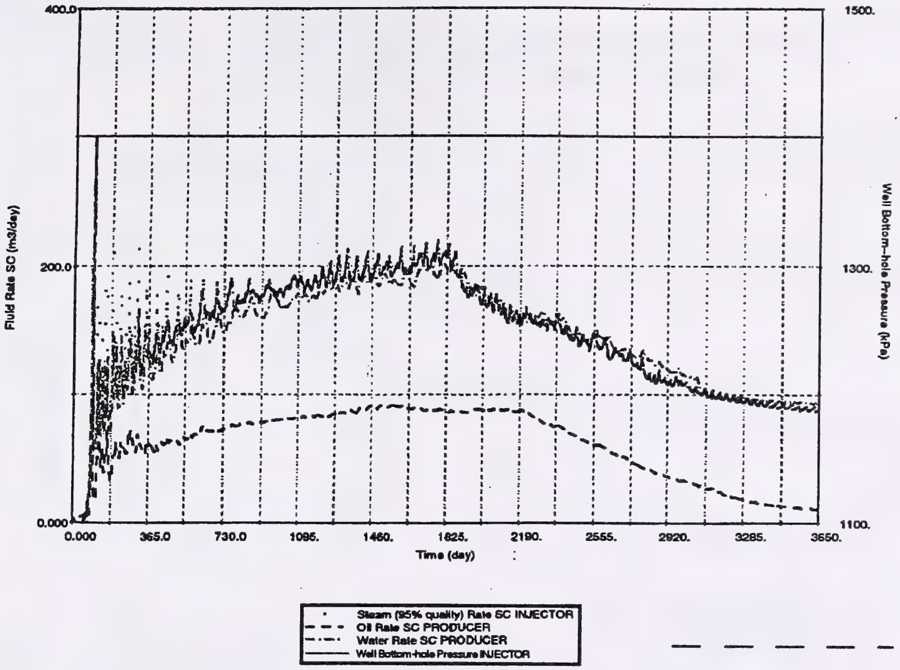
```
** ================  INITIAL CONDITIONS  ===================

*initial

*pres *con 1400.0

*temp *con 7.0

*so *ijk
1:30  1  1:2       0.85
1:30  1  3         0.85
1:30  1  4         0.85
1:30  1  5         0.75
1:30  1  6:7       0.85
1:30  1  8         0.75
1:30  1  9:10      0.85
1:30  1  11:16     0.75

*molefrac *oil *con  0.0  1.0


** ================  NUMERICAL CONTROL  =====================

*numerical

*aim            *off
*dtmax          15.0
*maxsteps       50000
*north          8
*itermax        60
*unrelax        -1
*sdegree        2
*sorder         rcmrb
*mintemp        1
*minpres        50
*norm           *press 250.0
                *satur 0.2
                *temp 50.       *y      0.2     *x      0.2

*converge       *press 30.
                *satur 0.04     *y      .04     *x      .04
                *temp   1.0

*pvtoscmax      4
```

File: Athabasca Base Case.dat 3

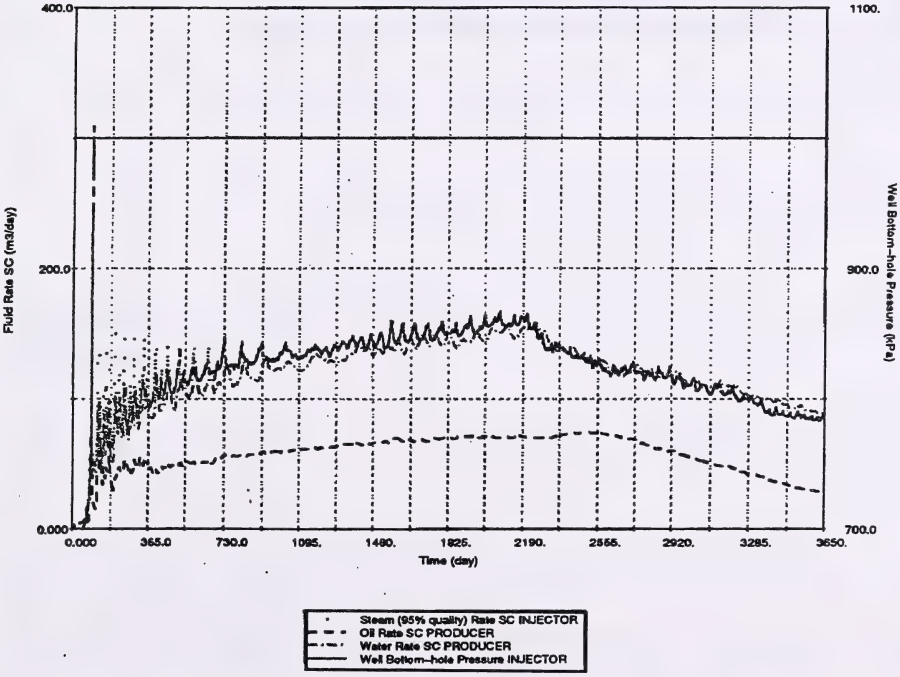
```
** ===============  RECURRENT DATA  ===========================

*run

*date 2000 1 1  *dtwell 1.0e-2

*well 1 'INJECTOR'  *frac   0.5
*injector *mobweight 1
*tinjw 194.8  *qual 0.95
*operate *max *bhp 1400.0
*operate *max *water 300.
*operate *max *bhp 1400.0
*geometry *j 0.110 0.363 0.5  0.0
*perf *geo 1
1  1  4
*uhtr *ijk
1  1  4     0.110e9
*tmpset *ijk
1  1  4     194.8

*well 2 'PRODUCER'  *frac   0.5
*producer 2
*operate *min *bhp 900.0
*operate *max *steamtrap 5.0
*operate *min *bhp 900.0
*operate *max *liquid 500.0
*geometry *j 0.110 0.363 0.5  0.0
*perf *geo 2
1  1  1
*uhtr *ijk
1  1  1     0.110e9
*tmpset *ijk
1  1  1     194.8

*dtmax 1.0

*time 10.0
*time 20.0
*time 36.5    **0.1 yrs
*time 50.
*time 60.
*time 70.
*time 90.
*time 100.
*time 120.
*time 150.
*time 180.
*time 210.
*time 250.
*time 300.
*time 350.
*time 365.0

*uhtr *ijk 1 1 4 0
*uhtr *ijk 1 1 1 0

*dtwell 0.01
```

```
*time 400.
*time 420.
*time 438     **1.2 yrs
*time 455.
*time 547.5
*time 584.    **1.6 yrs
*time 657.    **1.8 yrs
*time 730.              **2.0 yrs
*time 803.    **2.2 yrs
*time 876.    **2.4 yrs
*time 949.    **2.6 yrs
*time 1022.   **2.8 yrs
*time 1095.             **3.0 yrs
*time 1168.   **3.2 yrs
*time 1241.   **3.4 yrs
*time 1314.   **3.6 yrs
*time 1387.   **3.8 yrs
*time 1460.              **4.0 yrs
*time 1533.   **4.3 yrs
*time 1565.
*time 1606.   **4.4 yrs
*time 1679.   **4.6 yrs
*time 1752.   **4.8 yrs
*time 1825.             **5.0 yrs
*time 1898.   **5.2 yrs
*time 1971.   **5.4 yrs
*time 2044.   **5.6 yrs
*time 2117.   **5.8 yrs
*time 2190.             **6.0 yrs
*time 2263.   **6.2 yrs
*time 2336.   **6.4 yrs
*time 2409.   **6.6 yrs
*time 2482.   **6.8 yrs
*time 2555.             **7.0 yrs
*time 2628.   **7.2 yrs
*time 2701.   **7.4 yrs
*time 2774.   **7.6 yrs
*time 2847.   **7.8 yrs
*time 2920.             **8.0 yrs
*time 2993.   **8.2 yrs
*time 3066.   **8.4 yrs
*time 3139.   **8.6 yrs
*time 3212.   **8.8 yrs
*time 3285.             **9.0 yrs
*time 3358.   **9.2 yrs
*time 3431.   **9.4 yrs
*time 3504.   **9.6 yrs
*time 3577.   **9.8 yrs
*time 3650.              **10.0 yrs


*stop
```

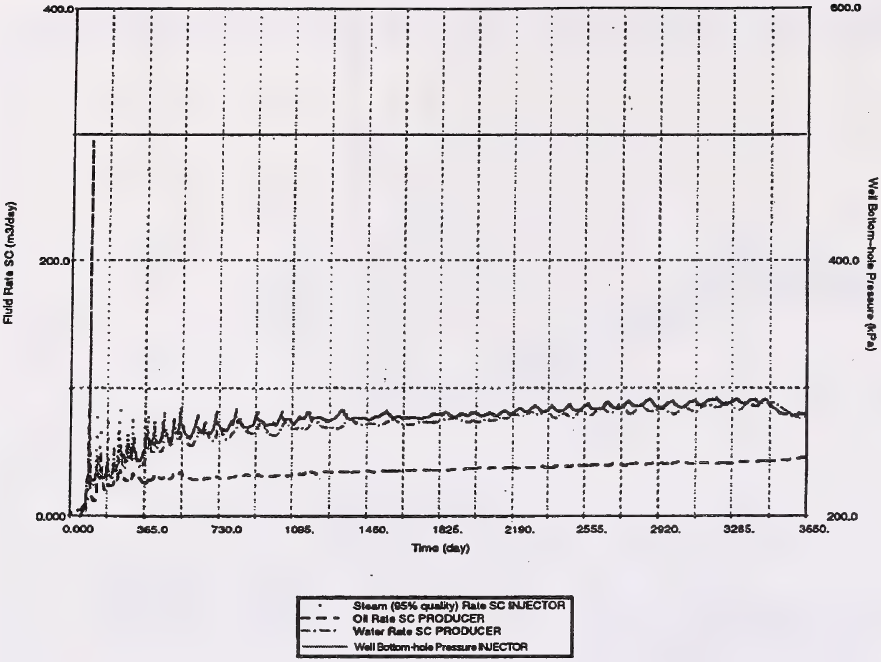
File: Athabasca_Base_Case.dat 4



Athabasca McMurray Effect of Overburden Study
140m Overburden

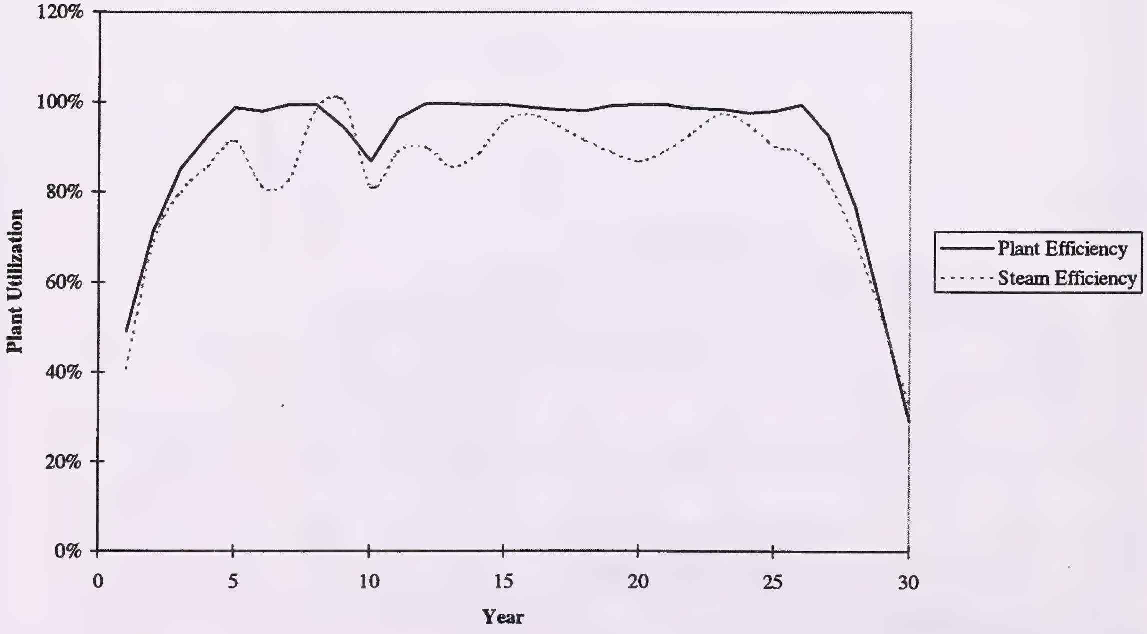


Athabasca McMurray Effect of Overburden Study
100m Overburden

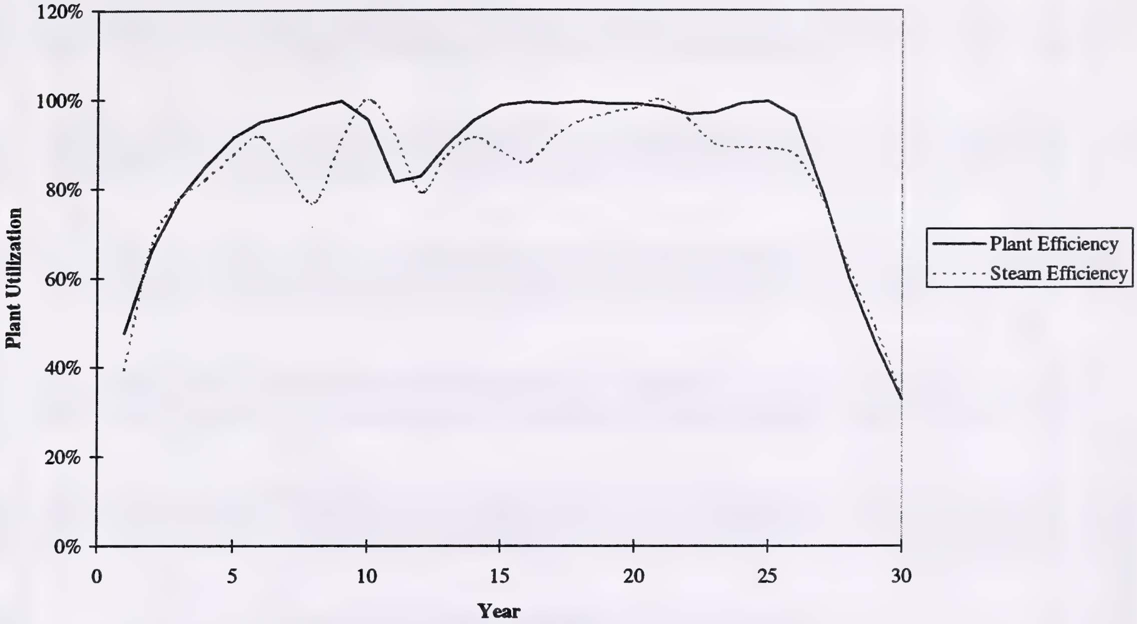


Athabasca McMurray Effect of Overburden Study
50m Overburden

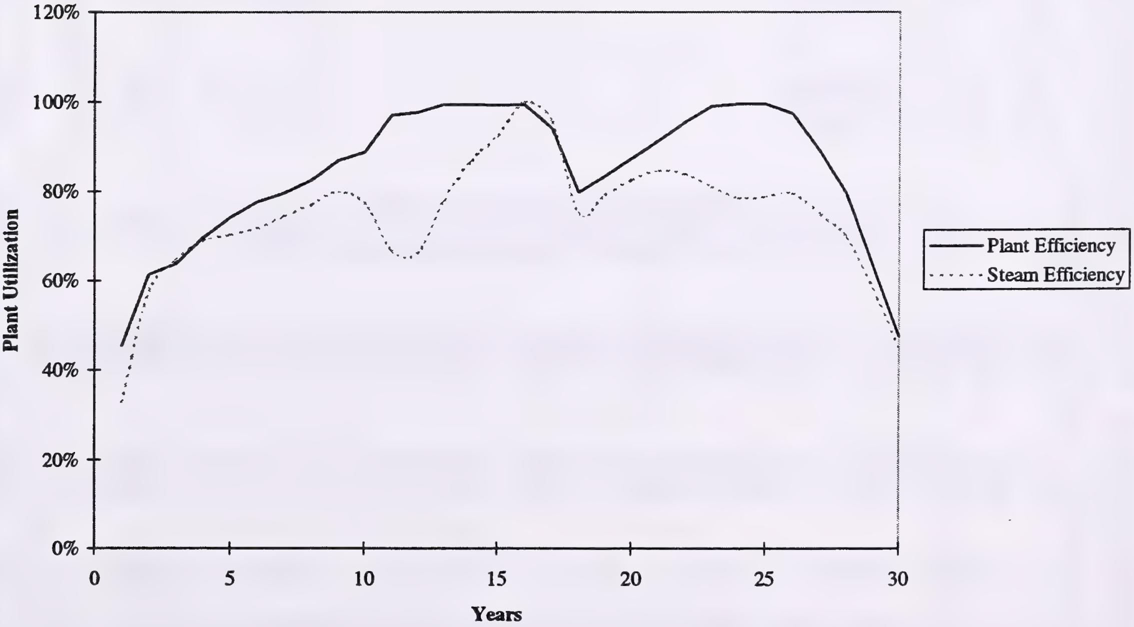
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 140 m Overburden



Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 100 m Overburden



Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 50 m Overburden



Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 140 m Overburden

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m³/d)	Steam Injection (m³/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$73	$235	$307						
1997	18			$24,300	$99	$319	$24,717						
1998	18			$24,300	$24,140	$78,072	$126,511						
1999	16			$21,600	$24,761	$80,082	$126,443						
2000	9	2,342	5,003	$12,150	$6,584	$21,293	$40,027	$10,235	$2,757	$756	$743	$10,850	$25,341
2001	9	3,400	8,484	$12,150			$12,150	$17,358	$4,676	$1,010	$1,263	$10,850	$35,157
2002	9	4,059	9,837	$12,150			$12,150	$20,125	$5,421	$1,167	$1,492	$10,850	$39,056
2003	9	4,419	10,532	$12,150			$12,150	$21,548	$5,805	$1,254	$1,642	$10,850	$41,099
2004	9	4,717	11,234	$12,150			$12,150	$22,984	$6,192	$1,325	$1,741	$10,850	$43,092
2005	9	4,670	9,993	$12,150			$12,150	$20,445	$5,508	$1,314	$1,640	$10,850	$39,757
2006	9	4,745	10,141	$12,150			$12,150	$20,747	$5,589	$1,332	$1,650	$10,850	$40,167
2007	9	4,743	12,118	$12,150			$12,150	$24,793	$6,679	$1,331	$1,975	$10,850	$45,628
2008	9	4,498	12,290	$12,150			$12,150	$25,144	$6,774	$1,273	$1,933	$10,850	$45,973
2009	9	4,140	9,971	$12,150			$12,150	$20,401	$5,496	$1,187	$1,526	$10,850	$39,460
2010	9	4,597	10,920	$12,150			$12,150	$22,341	$6,018	$1,296	$1,690	$10,850	$42,196
2011	9	4,755	11,061	$12,150			$12,150	$22,630	$6,096	$1,334	$1,749	$10,850	$42,660
2012	9	4,756	10,512	$12,150			$12,150	$21,507	$5,794	$1,334	$1,696	$10,850	$41,180
2013	9	4,740	10,902	$12,150			$12,150	$22,304	$6,008	$1,330	$1,773	$10,850	$42,266
2014	9	4,743	11,777	$12,150			$12,150	$24,094	$6,491	$1,331	$1,896	$10,850	$44,662
2015	9	4,711	11,953	$12,150			$12,150	$24,455	$6,588	$1,323	$1,877	$10,850	$45,094
2016	9	4,690	11,635	$12,150			$12,150	$23,804	$6,413	$1,319	$1,806	$10,850	$44,191
2017	9	4,678	11,246	$12,150			$12,150	$23,010	$6,198	$1,316	$1,750	$10,850	$43,124
2018	4	4,737	10,902	$5,400			$5,400	$22,305	$6,009	$1,330	$1,730	$10,850	$42,223
2019	0	4,741	10,687	$0			$0	$21,865	$5,890	$1,331	$1,718	$10,850	$41,654
2020	0	4,744	10,973	$0			$0	$22,450	$6,048	$1,331	$1,784	$10,850	$42,463
2021	0	4,700	11,479	$0			$0	$23,485	$6,327	$1,321	$1,842	$10,850	$43,825
2022	0	4,698	11,970	$0			$0	$24,489	$6,597	$1,321	$1,888	$10,850	$45,145
2023	0	4,656	11,690	$0			$0	$23,917	$6,443	$1,310	$1,814	$10,850	$44,334
2024	0	4,672	11,076	$0			$0	$22,660	$6,104	$1,314	$1,723	$10,850	$42,652
2025	0	4,741	10,907	$0			$0	$22,315	$6,011	$1,331	$1,728	$10,850	$42,235
2026	0	4,416	10,105	$0			$0	$20,674	$5,569	$1,253	$1,639	$10,850	$39,985
2027	0	3,667	8,550	$0			$0	$17,493	$4,712	$1,074	$1,419	$10,850	$35,548
2028	0	2,518	6,347	$0			$0	$12,986	$3,498	$798	$1,073	$10,850	$29,205
2029	0	1,394	3,966	$0			$0	$8,115	$2,186	$529	$679	$21,750	$33,258
Totals	218	47,116,536	112,515,287	$294,300	$55,656	$180,000	$529,956	$630,682	$169,898	$36,775	$48,879	$336,400	$1,222,633

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 100 m Overburden

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m³/d)	Steam Injection (m³/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$68	$235	$303						
1997	22			$29,700	$92	$319	$30,111						
1998	22			$29,700	$22,597	$78,072	$130,369						
1999	20			$27,000	$23,179	$80,082	$130,260						
2000	9	2,270	4,543	$12,150	$6,163	$21,293	$39,606	$9,294	$2,504	$739	$674	$10,850	$24,060
2001	9	3,164	7,795	$12,150			$12,150	$15,948	$4,296	$953	$1,161	$10,850	$33,209
2002	9	3,700	8,947	$12,150			$12,150	$18,305	$4,931	$1,081	$1,342	$10,850	$36,510
2003	9	4,060	9,456	$12,150			$12,150	$19,346	$5,212	$1,168	$1,457	$10,850	$38,032
2004	9	4,364	10,079	$12,150			$12,150	$20,621	$5,555	$1,240	$1,567	$10,850	$39,834
2005	9	4,527	10,551	$12,150			$12,150	$21,586	$5,815	$1,279	$1,637	$10,850	$41,168
2006	9	4,592	9,622	$12,150			$12,150	$19,686	$5,303	$1,295	$1,575	$10,850	$38,709
2007	9	4,684	8,844	$12,150			$12,150	$18,093	$4,874	$1,317	$1,444	$10,850	$36,579
2008	9	4,752	10,446	$12,150			$12,150	$21,371	$5,757	$1,333	$1,700	$10,850	$41,011
2009	9	4,552	11,501	$12,150			$12,150	$23,531	$6,339	$1,285	$1,872	$10,850	$43,877
2010	9	3,891	10,616	$12,150			$12,150	$21,719	$5,851	$1,127	$1,665	$10,850	$41,212
2011	9	3,944	9,105	$12,150			$12,150	$18,628	$5,018	$1,140	$1,390	$10,850	$37,026
2012	9	4,276	10,072	$12,150			$12,150	$20,608	$5,551	$1,219	$1,545	$10,850	$39,773
2013	9	4,548	10,532	$12,150			$12,150	$21,548	$5,805	$1,284	$1,637	$10,850	$41,124
2014	9	4,709	10,175	$12,150			$12,150	$20,817	$5,608	$1,323	$1,623	$10,850	$40,220
2015	9	4,740	9,866	$12,150			$12,150	$20,186	$5,438	$1,331	$1,590	$10,850	$39,395
2016	9	4,722	10,548	$12,150			$12,150	$21,582	$5,814	$1,326	$1,702	$10,850	$41,273
2017	1	4,747	10,947	$1,350			$1,350	$22,397	$6,033	$1,332	$1,784	$10,850	$42,396
2018	0	4,725	11,137	$0			$0	$22,785	$6,138	$1,327	$1,763	$10,850	$42,863
2019	0	4,719	11,283	$0			$0	$23,085	$6,219	$1,326	$1,759	$10,850	$43,239
2020	0	4,689	11,505	$0			$0	$23,538	$6,341	$1,318	$1,799	$10,850	$43,846
2021	0	4,611	10,988	$0			$0	$22,481	$6,056	$1,300	$1,707	$10,850	$42,393
2022	0	4,630	10,362	$0			$0	$21,199	$5,711	$1,304	$1,631	$10,850	$40,695
2023	0	4,730	10,265	$0			$0	$21,001	$5,657	$1,328	$1,634	$10,850	$40,471
2024	0	4,751	10,250	$0			$0	$20,971	$5,649	$1,333	$1,659	$10,850	$40,462
2025	0	4,586	10,047	$0			$0	$20,556	$5,537	$1,294	$1,640	$10,850	$39,876
2026	0	3,776	8,898	$0			$0	$18,205	$4,904	$1,100	$1,451	$10,850	$36,510
2027	0	2,860	7,125	$0			$0	$14,578	$3,927	$880	$1,170	$10,850	$31,405
2028	0	2,154	5,593	$0			$0	$11,444	$3,083	$711	$910	$10,850	$26,997
2029	0	1,563	3,838	$0			$0	$7,852	$2,115	$569	$611	$21,750	$32,899
Totals	218	45,272,809	104,001,483	$294,300	$52,099	$180,000	$526,399	$582,960	$157,042	$35,565	$45,099	$336,400	$1,157,065

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 50 m Overburden

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m³/d)	Steam Injection (m³/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$71	$235	$305						
1997	33			$44,550	$96	$319	$44,964						
1998	33			$44,550	$23,473	$78,072	$146,095						
1999	32			$43,200	$24,078	$80,082	$147,359						
2000	9	2,164	3,922	$12,150	$6,402	$21,293	$39,845	$8,023	$2,161	$713	$584	$10,850	$22,332
2001	9	2,931	6,900	$12,150			$12,150	$14,116	$3,803	$897	$1,033	$10,850	$30,699
2002	9	3,036	7,700	$12,150			$12,150	$15,753	$4,244	$922	$1,155	$10,850	$32,924
2003	9	3,324	8,230	$12,150			$12,150	$16,838	$4,536	$991	$1,242	$10,850	$34,457
2004	9	3,540	8,393	$12,150			$12,150	$17,172	$4,626	$1,043	$1,290	$10,850	$34,981
2005	9	3,704	8,583	$12,150			$12,150	$17,561	$4,731	$1,082	$1,323	$10,850	$35,547
2006	9	3,797	8,894	$12,150			$12,150	$18,198	$4,902	$1,105	$1,384	$10,850	$36,439
2007	9	3,936	9,201	$12,150			$12,150	$18,825	$5,071	$1,138	$1,439	$10,850	$37,324
2008	9	4,144	9,547	$12,150			$12,150	$19,533	$5,262	$1,188	$1,486	$10,850	$38,319
2009	9	4,239	9,247	$12,150			$12,150	$18,919	$5,097	$1,211	$1,490	$10,850	$37,566
2010	9	4,627	7,995	$12,150			$12,150	$16,358	$4,407	$1,304	$1,306	$10,850	$34,223
2011	9	4,661	7,910	$12,150			$12,150	$16,184	$4,360	$1,312	$1,279	$10,850	$33,984
2012	9	4,745	9,320	$12,150			$12,150	$19,069	$5,137	$1,332	$1,496	$10,850	$37,884
2013	9	4,741	10,377	$12,150			$12,150	$21,231	$5,719	$1,331	$1,683	$10,850	$40,814
2014	2	4,739	11,054	$2,700			$2,700	$22,617	$6,093	$1,330	$1,797	$10,850	$42,687
2015	0	4,743	11,951	$0			$0	$24,450	$6,587	$1,331	$1,916	$10,850	$45,134
2016	0	4,488	11,426	$0			$0	$23,378	$6,298	$1,270	$1,807	$10,850	$43,603
2017	0	3,808	8,974	$0			$0	$18,360	$4,946	$1,107	$1,371	$10,850	$36,633
2018	0	3,986	9,475	$0			$0	$19,384	$5,222	$1,150	$1,456	$10,850	$38,062
2019	0	4,174	9,869	$0			$0	$20,191	$5,439	$1,195	$1,525	$10,850	$39,200
2020	0	4,359	10,116	$0			$0	$20,696	$5,575	$1,239	$1,573	$10,850	$39,934
2021	0	4,563	10,033	$0			$0	$20,527	$5,530	$1,288	$1,582	$10,850	$39,778
2022	0	4,730	9,695	$0			$0	$19,835	$5,343	$1,328	$1,544	$10,850	$38,901
2023	0	4,752	9,402	$0			$0	$19,235	$5,182	$1,333	$1,505	$10,850	$38,105
2024	0	4,751	9,414	$0			$0	$19,261	$5,189	$1,333	$1,518	$10,850	$38,150
2025	0	4,649	9,508	$0			$0	$19,452	$5,240	$1,309	$1,545	$10,850	$38,395
2026	0	4,252	8,971	$0			$0	$18,355	$4,945	$1,214	$1,482	$10,850	$36,845
2027	0	3,794	8,321	$0			$0	$17,024	$4,586	$1,104	$1,376	$10,850	$34,940
2028	0	3,015	6,944	$0			$0	$14,207	$3,827	$917	$1,150	$10,850	$30,951
2029	0	2,269	5,373	$0			$0	$10,993	$2,961	$739	$890	$22,150	$37,733
Totals	226	44,040,754	97,362,206	$305,100	$54,120	$180,000	$539,220	$545,744	$147,017	$34,756	$42,225	$336,800	$1,106,542

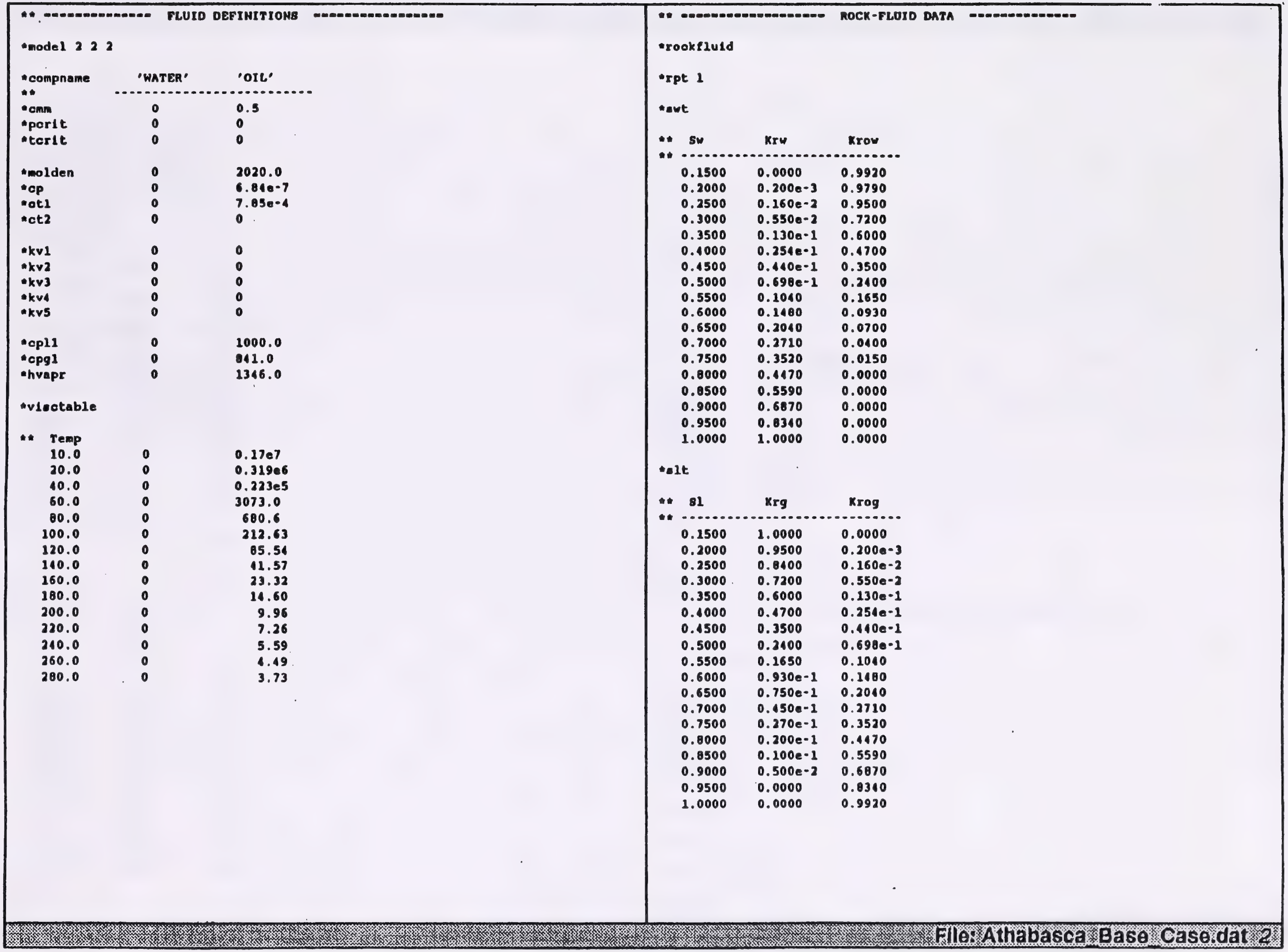
Appendix 2

Pay Thickness Simulation Data Set and Results, Commercial Plant Utilization, Detailed Plant Bitumen Forecast, and Undiscounted Cost for Athabasca McMurray

```
** SOURCE DATA SET: ATHABASCA MCMURRAY CASE STUDY - BASE CASE FOR EFFECT OF OVER
BURDEN & NET PAY
** CMG STARS SIMULATION
**
** No Thief Zone (i.e. Gas Cap / Overlying Water Sands)
** 2D run assuming a Dead Oil @ Reservoir Conditions
** Model Dimensions: 45 m x 500 m x 24 m
** 500 m Length Horizontal Wells and 24 m of Pay above the Producer Wells
** Initial Reservoir Pressure = 1400 kPa
** One-Half Well Pair Model / Forecast based on Single Well Pair Basis
** (Well Pair assumes perfect symmetry)
** Inter-Well Distance is 90 m and Injector/Producer Vertical Spacing is 4.5 m
** Grid Block thickness is constant in i-direction (30 - 1.5 m), j-direction
** consists of a single slab of 500 m, and k-direction is also constant ( 16 - 1
.5 m)
** No "Short Circuit Layer" (i.e. 2D Model)
** Injput and Output Units are SI; and time basis is days
**
** --------------  INPUT/OUTPUT  -----------------------

*filename   *output 'Athabasca_Base_Case.out' *index-out *main-results-out

*title1 'Joint ADOE-EUB SAGD Study'
*title2 'Case Study: Athabasca McMurray (140 m Overburden / 24 m Net Pay)'
*title3 'Pattern Simulation: 1/2 Well Pair Model'

**restart

*maxerror 1
*wrst *time

*prntorien  2  0
*outprn *grid *pres *temp *sw *so *sg *x *y
*outprn *well *brief
*wsrf *grid *time
*outsrf *grid *pres *temp *sw *so *sg *x *y


** ----------  GRID AND RESERVOIR DEFINITION ----------

*grid *cart 30 1 16
*kdir *up

*di *ivar 30*1.5

*dj *jvar 500.

*dk *kvar 16*1.5

*dtop *con 140.0

*por *ijk
1:30  1  1:2     0.35
1:30  1  3       0.35
1:30  1  4       0.35
1:30  1  5       0.30
1:30  1  6:7     0.35
1:30  1  8       0.30
```

```
1:30  1  9:10    0.35
1:30  1  11:16   0.30

*permi *ijk
1:30  1  1:2     10000
1:30  1  3       10000
1:30  1  4       10000
1:30  1  5       2000
1:30  1  6:7     10000
1:30  1  8       2000
1:30  1  9:10    10000
1:30  1  11:16   2000

*permj *ijk
1:30  1  1:2     10000
1:30  1  3       10000
1:30  1  4       10000
1:30  1  5       2000
1:30  1  6:7     10000
1:30  1  8       2000
1:30  1  9:10    10000
1:30  1  11:16   2000

*permk *ijk
1:30  1  1:2     2500
1:30  1  3       2500
1:30  1  4       2500
1:30  1  5       200
1:30  1  6:7     2500
1:30  1  8       200
1:30  1  9:10    2500
1:30  1  11:16   200

*cpor 7.0e-6 *prpor 100.0

*rockcp 2.390e6
*cpc    17.0
*thconr 1.469e5
*thconw 1.469e5
*thcono 1.469e5

*hlossprop *overbur 2.390e6 1.469e5 *hlosst 7.0 *hlosstdiff 0.1
*hlossprop *underbur 2.390e6 2.333e5 *hlosst 7.0 *hlosstdiff 0.1
```

File: Athabasca Base Case.dat 7



```
** --------------  FLUID DEFINITIONS  -----------------

*model 2 2 2

*compname      'WATER'      'OIL'
**           --------------------------
*cmm             0          0.5
*pcrit           0          0
*tcrit           0          0

*molden          0          2020.0
*cp              0          6.84e-7
*ct1             0          7.85e-4
*ct2             0          0

*kv1             0          0
*kv2             0          0
*kv3             0          0
*kv4             0          0
*kv5             0          0

*cpl1            0          1000.0
*cpg1            0          841.0
*hvapr           0          1346.0

*visctable

**  Temp
   10.0         0          0.17e7
   20.0         0          0.319e6
   40.0         0          0.223e5
   60.0         0          3073.0
   80.0         0           680.6
  100.0         0           212.63
  120.0         0            85.54
  140.0         0            41.57
  160.0         0            23.32
  180.0         0            14.60
  200.0         0             9.96
  220.0         0             7.26
  240.0         0             5.59
  260.0         0             4.49
  280.0         0             3.73
```

```
** ------------------  ROCK-FLUID DATA  --------------

*rockfluid

*rpt 1

*swt

**  Sw        Krw        Krow
** ----------------------------
   0.1500    0.0000     0.9920
   0.2000    0.200e-3   0.9790
   0.2500    0.160e-2   0.9500
   0.3000    0.550e-2   0.7200
   0.3500    0.130e-1   0.6000
   0.4000    0.254e-1   0.4700
   0.4500    0.440e-1   0.3500
   0.5000    0.698e-1   0.2400
   0.5500    0.1040     0.1650
   0.6000    0.1480     0.0930
   0.6500    0.2040     0.0700
   0.7000    0.2710     0.0400
   0.7500    0.3520     0.0150
   0.8000    0.4470     0.0000
   0.8500    0.5590     0.0000
   0.9000    0.6870     0.0000
   0.9500    0.8340     0.0000
   1.0000    1.0000     0.0000

*slt

**  Sl        Krg        Krog
** ----------------------------
   0.1500    1.0000     0.0000
   0.2000    0.9500     0.200e-3
   0.2500    0.8400     0.160e-2
   0.3000    0.7200     0.550e-2
   0.3500    0.6000     0.130e-1
   0.4000    0.4700     0.254e-1
   0.4500    0.3500     0.440e-1
   0.5000    0.2400     0.698e-1
   0.5500    0.1650     0.1040
   0.6000    0.930e-1   0.1480
   0.6500    0.750e-1   0.2040
   0.7000    0.450e-1   0.2710
   0.7500    0.270e-1   0.3520
   0.8000    0.200e-1   0.4470
   0.8500    0.100e-1   0.5590
   0.9000    0.500e-2   0.6870
   0.9500    0.0000     0.8340
   1.0000    0.0000     0.9920
```

File: Athabasca_Base_Case.dat 2

```
*rpt 2

*swt

**  Sw          Krw          Krow
** -----------------------------
   0.25        0.0          0.95
   0.3         0.0005       0.72
   0.35        0.003        0.6
   0.4         0.009        0.47
   0.45        0.022        0.35
   0.5         0.046        0.24
   0.55        0.081        0.165
   0.6         0.131        0.093
   0.65        0.186        0.07
   0.7         0.257        0.04
   0.75        0.341        0.015
   0.8         0.436        0.
   0.85        0.551        0.
   0.9         0.683        0.
   0.95        0.832        0.
   1.0         1.0          0.

*slt

**  Sl          Krg          Krog
** -----------------------------
   0.25        0.84         0.
   0.3         0.72         0.0005
   0.35        0.6          0.003
   0.4         0.47         0.009
   0.45        0.35         0.022
   0.5         0.24         0.046
   0.55        0.165        0.081
   0.6         0.093        0.131
   0.65        0.075        0.186
   0.7         0.045        0.257
   0.75        0.027        0.341
   0.8         0.02         0.436
   0.85        0.01         0.551
   0.9         0.005        0.683
   0.95        0.           0.832
   1.0         0.           0.95

*krtype *ijk
1:30  1  1:2        1
1:30  1  3          1
1:30  1  4          1
1:30  1  5          2
1:30  1  6:7        1
1:30  1  8          2
1:30  1  9:10       1
1:30  1  11:16      2
```

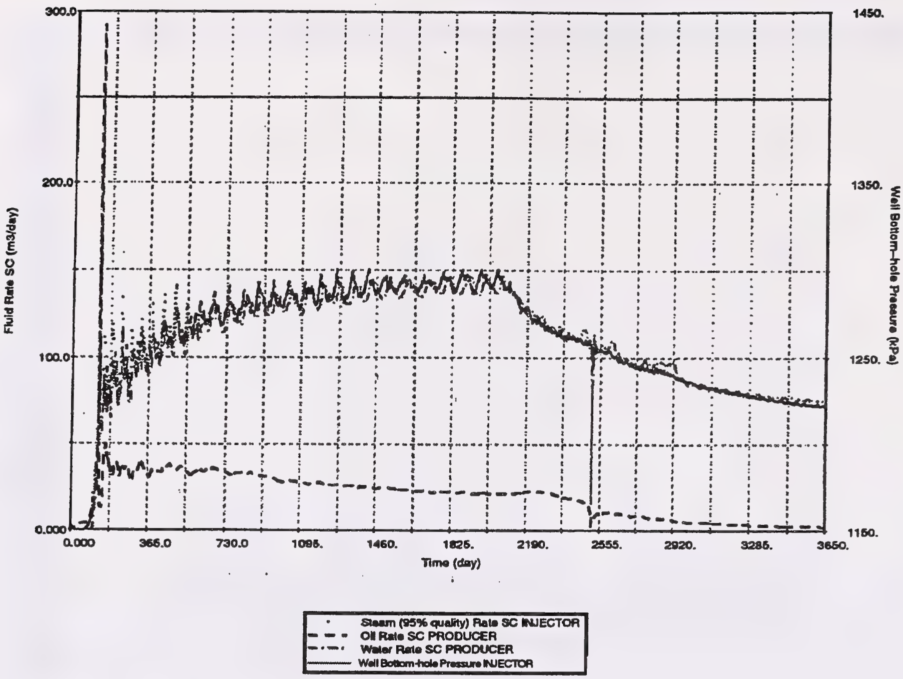
```
** ----------------  INITIAL CONDITIONS  ------------------

*initial

*pres *con 1400.0

*temp *con 7.0

*so *ijk
1:30  1  1:2        0.85
1:30  1  3          0.85
1:30  1  4          0.85
1:30  1  5          0.75
1:30  1  6:7        0.85
1:30  1  8          0.75
1:30  1  9:10       0.85
1:30  1  11:16      0.75

*molefrac *oil *con  0.0  1.0


** ----------------  NUMERICAL CONTROL  -------------------

*numerical

*aim            *off
*dtmax          15.0
*maxsteps       50000
*north          8
*itermax        60
*unrelax        -1
*sdegree        2
*sorder         rcmrb
*mintemp        1
*minpres        50
*norm           *press 250.0
                *satur 0.2
                *temp 50.       *y      0.2      *x      0.2

*converge       *press 30.
                *satur 0.04     *y      .04      *x      .04
                *temp   1.0

*pvtoscmax      4
```

File: Athabasca Base Case.dat 3

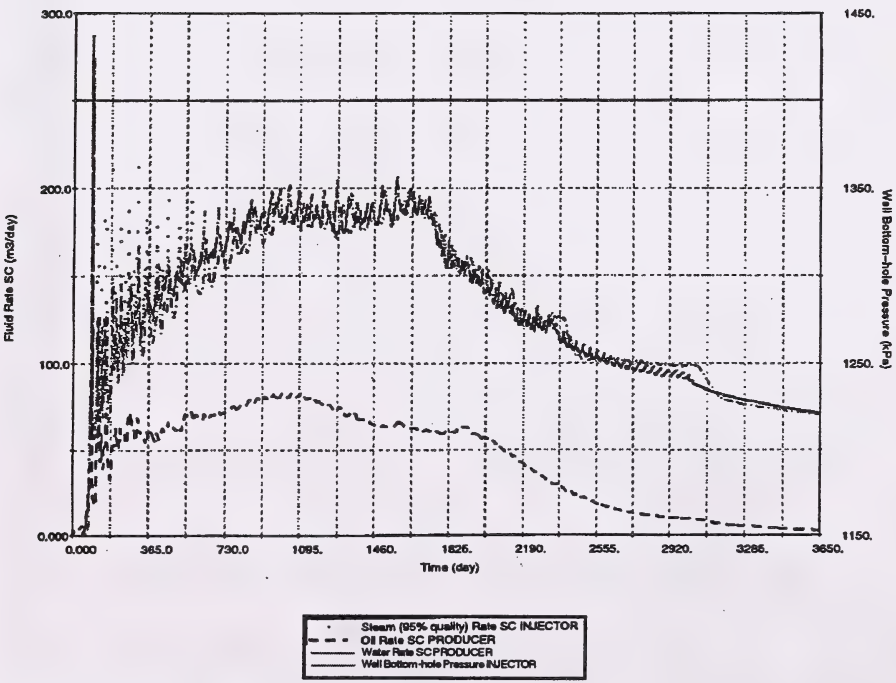
```
** ===============  RECURRENT DATA  ===========================

*run

*date 2000 1 1  *dtwell 1.0e-2

*well 1 'INJECTOR'  *frac   0.5
*injector *mobweight 1
*tinjw 194.8  *qual 0.95
*operate *max *bhp 1400.0
*operate *max *water 300.
*operate *max *bhp 1400.0
*geometry *j 0.110 0.363 0.5  0.0
*perf *geo 1
1  1  4
*uhtr *ijk
1  1  4     0.110e9
*tmpset *ijk
1  1  4     194.8

*well 2 'PRODUCER'  *frac   0.5
*producer 2
*operate *min *bhp 900.0
*operate *max *steamtrap 5.0
*operate *min *bhp 900.0
*operate *max *liquid 500.0
*geometry *j 0.110 0.363 0.5  0.0
*perf *geo 2
1  1  1
*uhtr *ijk
1  1  1     0.110e9
*tmpset *ijk
1  1  1     194.8

*dtmax 1.0

*time 10.0
*time 20.0
*time 36.5    **0.1 yrs
*time 50.
*time 60.
*time 70.
*time 90.
*time 100.
*time 120.
*time 150.
*time 180.
*time 210.
*time 250.
*time 300.
*time 350.
*time 365.0

*uhtr *ijk 1 1 4 0
*uhtr *ijk 1 1 1 0

*dtwell 0.01
```

```
*time 400.
*time 420.
*time 438     **1.2 yrs
*time 455.
*time 547.5
*time 584.    **1.6 yrs
*time 657.    **1.8 yrs
*time 730.              **2.0 yrs
*time 803.    **2.2 yrs
*time 876.    **2.4 yrs
*time 949.    **2.6 yrs
*time 1022.   **2.8 yrs
*time 1095.             **3.0 yrs
*time 1168.   **3.2 yrs
*time 1241.   **3.4 yrs
*time 1314.   **3.6 yrs
*time 1387.   **3.8 yrs
*time 1460.              **4.0 yrs
*time 1533.   **4.3 yrs
*time 1565.
*time 1606.   **4.4 yrs
*time 1679.   **4.6 yrs
*time 1752.   **4.8 yrs
*time 1825.             **5.0 yrs
*time 1898.   **5.2 yrs
*time 1971.   **5.4 yrs
*time 2044.   **5.6 yrs
*time 2117.   **5.8 yrs
*time 2190.             **6.0 yrs
*time 2263.   **6.2 yrs
*time 2336.   **6.4 yrs
*time 2409.   **6.6 yrs
*time 2482.   **6.8 yrs
*time 2555.             **7.0 yrs
*time 2628.   **7.2 yrs
*time 2701.   **7.4 yrs
*time 2774.   **7.6 yrs
*time 2847.   **7.8 yrs
*time 2920.             **8.0 yrs
*timc 2993.   **8.2 yrs
*time 3066.   **8.4 yrs
*time 3139.   **8.6 yrs
*time 3212.   **8.8 yrs
*time 3285.             **9.0 yrs
*time 3358.   **9.2 yrs
*time 3431.   **9.4 yrs
*time 3504.   **9.6 yrs
*time 3577.   **9.8 yrs
*time 3650.             **10.0 yrs


*stop
```

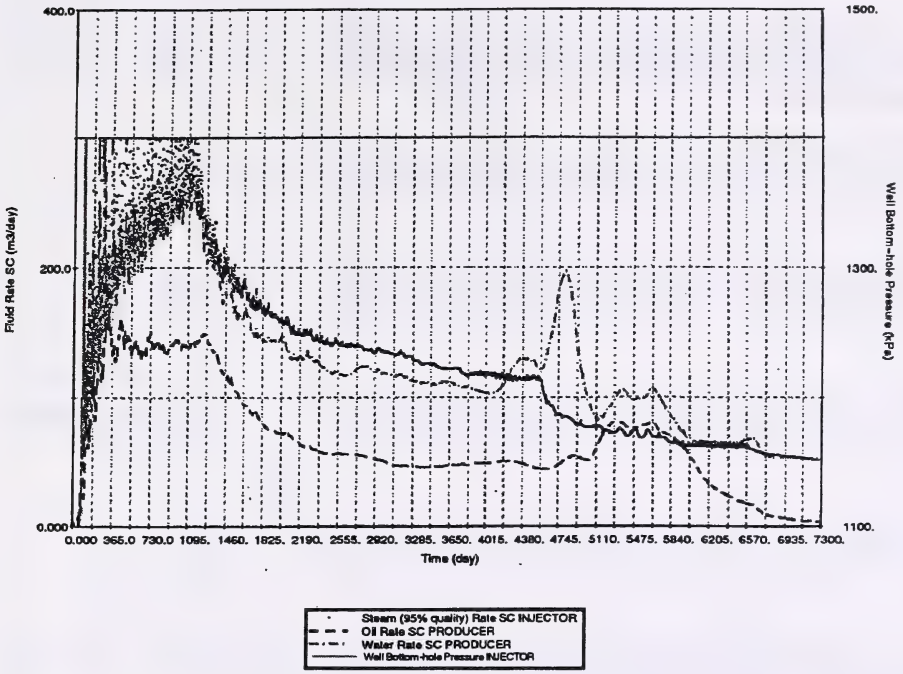
File: Athabasca Base Case.dat 4



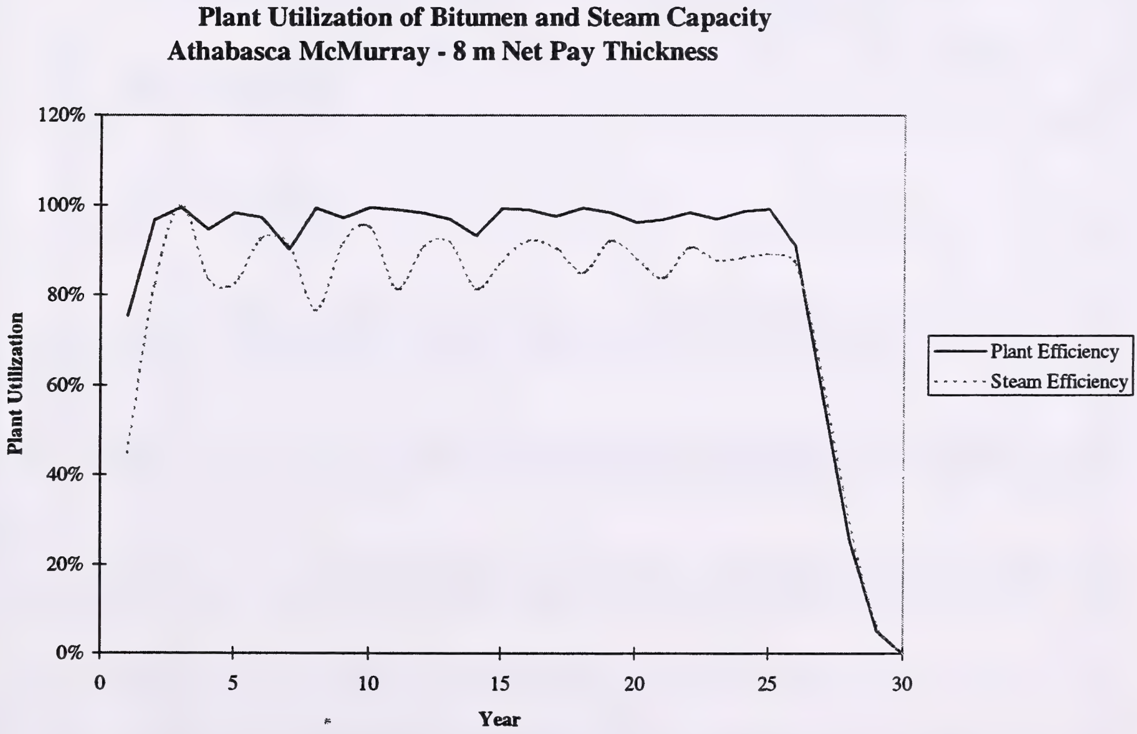
Athabasca McMurray Effect of Net Pay Thickness Study
8m Net Pay Thickness

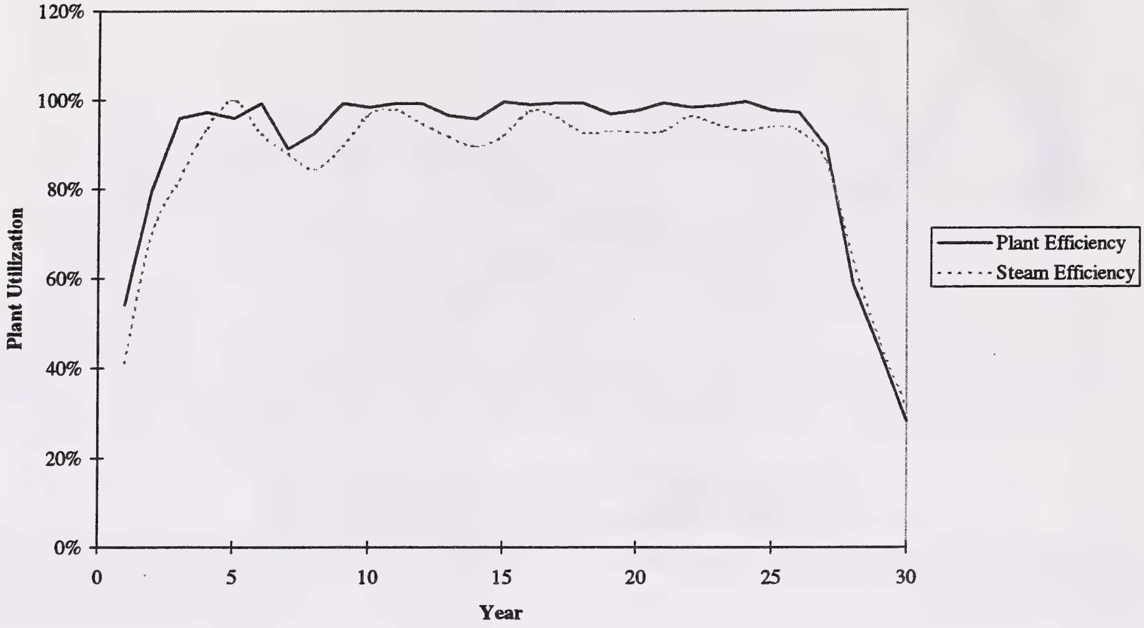


Athabasca McMurray Effect of Net Pay Thickness Study
16m Net Pay Thickness

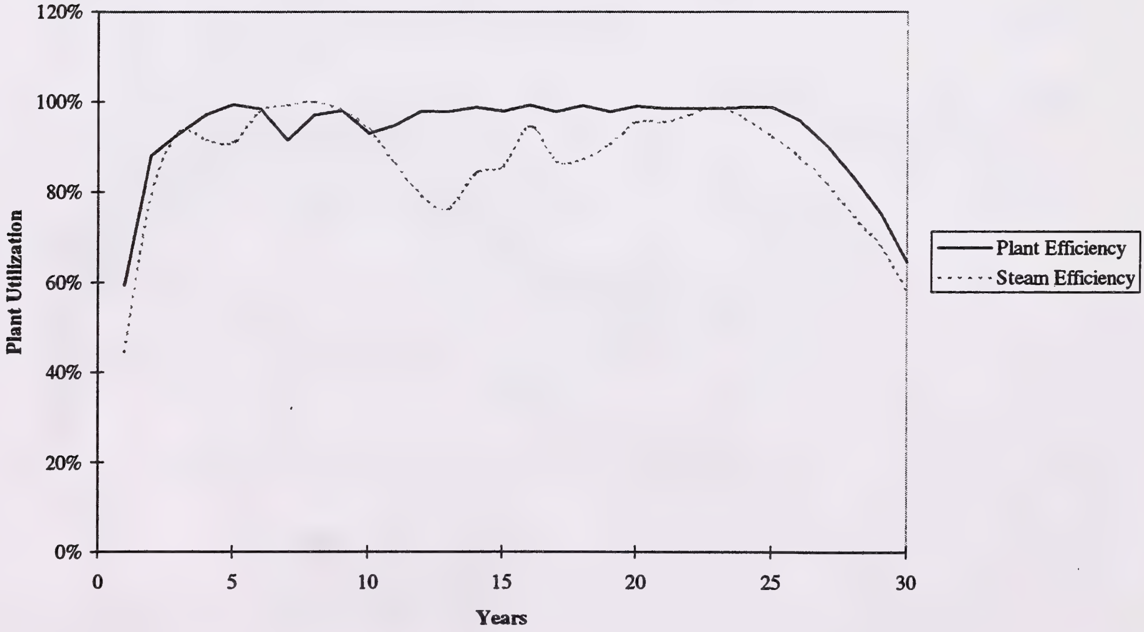


Athabasca McMurray Effect of Net Pay Thickness Study
45m Net Pay Thickness


Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 8 m Net Pay Thickness



Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 16 m Net Pay Thickness



Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - Case 2 - 45 m Net Pay Thickness

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 8 m Net Pay Thickness

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m³/d)	Steam Injection (m³/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$117	$235	$352						
1997	44			$59,400	$159	$319	$59,878						
1998	44			$59,400	$38,967	$78,072	$176,439						
1999	44			$59,400	$39,970	$80,082	$179,452						
2000	12	3,595	8,874	$16,200	$10,628	$21,293	$48,121	$18,155	$4,891	$1,056	$1,350	$10,850	$36,302
2001	16	4,612	16,369	$21,600			$21,600	$33,490	$9,022	$1,300	$2,549	$10,850	$57,211
2002	108	4,747	19,839	$145,800			$145,800	$40,589	$10,934	$1,332	$3,141	$10,850	$66,846
2003	9	4,506	16,571	$12,150			$12,150	$33,903	$9,133	$1,274	$2,585	$10,850	$57,746
2004	35	4,687	16,369	$47,250			$47,250	$33,491	$9,022	$1,318	$2,545	$10,850	$57,225
2005	90	4,636	18,369	$121,500			$121,500	$37,582	$10,124	$1,306	$2,901	$10,850	$62,764
2006	9	4,301	18,033	$12,150			$12,150	$36,894	$9,939	$1,225	$2,831	$10,850	$61,739
2007	35	4,740	15,201	$47,250			$47,250	$31,101	$8,378	$1,331	$2,356	$10,850	$54,016
2008	32	4,633	18,184	$43,200			$43,200	$37,204	$10,022	$1,305	$2,857	$10,850	$62,239
2009	72	4,748	18,885	$97,200			$97,200	$38,637	$10,408	$1,332	$2,969	$10,850	$64,197
2010	22	4,725	16,142	$29,700			$29,700	$33,026	$8,897	$1,327	$2,512	$10,850	$56,612
2011	54	4,685	18,008	$72,900			$72,900	$36,842	$9,925	$1,317	$2,826	$10,850	$61,760
2012	56	4,627	18,185	$75,600			$75,600	$37,205	$10,023	$1,303	$2,861	$10,850	$62,242
2013	24	4,448	16,165	$32,400			$32,400	$33,073	$8,909	$1,260	$2,522	$10,850	$56,615
2014	50	4,731	17,359	$67,500			$67,500	$35,515	$9,567	$1,328	$2,715	$10,850	$59,975
2015	64	4,725	18,282	$86,400			$86,400	$37,404	$10,076	$1,327	$2,873	$10,850	$62,530
2016	22	4,651	17,945	$29,700			$29,700	$36,715	$9,891	$1,309	$2,811	$10,850	$61,576
2017	44	4,736	16,867	$59,400			$59,400	$34,509	$9,296	$1,330	$2,635	$10,850	$58,620
2018	46	4,693	18,271	$62,100			$62,100	$37,381	$10,070	$1,319	$2,869	$10,850	$62,490
2019	48	4,584	17,506	$64,800			$64,800	$35,817	$9,649	$1,293	$2,744	$10,850	$60,353
2020	32	4,616	16,618	$43,200			$43,200	$34,000	$9,159	$1,301	$2,597	$10,850	$57,907
2021	48	4,693	17,973	$64,800			$64,800	$36,771	$9,906	$1,319	$2,818	$10,850	$61,664
2022	56	4,625	17,419	$75,600			$75,600	$35,639	$9,601	$1,303	$2,732	$10,850	$60,125
2023	28	4,705	17,545	$37,800			$37,800	$35,895	$9,670	$1,322	$2,744	$10,850	$60,482
2024	14	4,727	17,676	$18,900			$18,900	$36,165	$9,742	$1,328	$2,769	$10,850	$60,853
2025	0	4,341	17,259	$0			$0	$35,311	$9,512	$1,235	$2,713	$10,850	$59,621
2026	0	2,763	12,179	$0			$0	$24,918	$6,713	$857	$1,924	$10,850	$45,261
2027	0	1,215	5,870	$0			$0	$12,010	$3,235	$486	$931	$10,850	$27,512
2028	0	243	1,302	$0			$0	$2,664	$718	$253	$206	$10,850	$14,691
2029	0	0	0	$0			$0	$0	$0	$195	$0	$68,750	$68,945
Totals	1158	45,163,965	169,822,471	$1,563,300	$89,841	$180,000	$1,833,141	$951,906	$256,432	$35,493	$72,886	$383,400	$1,700,118

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 16 m Net Pay Thickness

Year	Well Pairs Drilled	Bitumen Prod. (m^3/d)	Steam Injection (m^3/d)	Capital Cost (Thousand $)				Operating Cost (Thousand $)					
				Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$78	$235	$313						
1997	19			$25,650	$106	$319	$26,075						
1998	19			$25,650	$26,070	$78,072	$129,791						
1999	18			$24,300	$26,741	$80,082	$131,122						
2000	9	2,579	5,454	$12,150	$7,110	$21,293	$40,554	$11,159	$3,006	$813	$813	$10,850	$26,641
2001	9	3,792	9,286	$12,150			$12,150	$18,998	$5,118	$1,104	$1,394	$10,850	$37,464
2002	9	4,577	10,901	$12,150			$12,150	$22,302	$6,008	$1,292	$1,712	$10,850	$42,164
2003	9	4,643	12,437	$12,150			$12,150	$25,445	$6,855	$1,307	$1,957	$10,850	$46,413
2004	9	4,574	13,272	$12,150			$12,150	$27,155	$7,315	$1,291	$2,118	$10,850	$48,729
2005	19	4,734	12,257	$25,650			$25,650	$25,077	$6,756	$1,329	$1,990	$10,850	$46,002
2006	9	4,243	11,666	$12,150			$12,150	$23,869	$6,430	$1,211	$1,841	$10,850	$44,202
2007	9	4,418	11,193	$12,150			$12,150	$22,900	$6,169	$1,253	$1,731	$10,850	$42,904
2008	9	4,733	11,899	$12,150			$12,150	$24,344	$6,558	$1,329	$1,883	$10,850	$44,964
2009	9	4,688	12,843	$12,150			$12,150	$26,276	$7,078	$1,318	$2,031	$10,850	$47,553
2010	10	4,732	12,973	$13,500			$13,500	$26,543	$7,150	$1,329	$2,064	$10,850	$47,936
2011	20	4,731	12,574	$27,000			$27,000	$25,726	$6,930	$1,328	$2,027	$10,850	$46,861
2012	9	4,602	12,184	$12,150			$12,150	$24,928	$6,715	$1,297	$1,911	$10,850	$45,701
2013	9	4,569	11,880	$12,150			$12,150	$24,306	$6,548	$1,290	$1,854	$10,850	$44,848
2014	12	4,748	12,217	$16,200			$16,200	$24,995	$6,733	$1,333	$1,950	$10,850	$45,862
2015	9	4,719	12,952	$12,150			$12,150	$26,498	$7,138	$1,325	$2,047	$10,850	$47,859
2016	21	4,735	12,773	$28,350			$28,350	$26,132	$7,040	$1,329	$2,025	$10,850	$47,377
2017	9	4,740	12,317	$12,150			$12,150	$25,200	$6,789	$1,331	$1,973	$10,850	$46,143
2018	9	4,625	12,351	$12,150			$12,150	$25,269	$6,807	$1,303	$1,936	$10,850	$46,165
2019	9	4,659	12,311	$12,150			$12,150	$25,188	$6,785	$1,311	$1,934	$10,850	$46,068
2020	15	4,743	12,352	$20,250			$20,250	$25,271	$6,808	$1,331	$1,980	$10,850	$46,240
2021	9	4,691	12,800	$12,150			$12,150	$26,189	$7,055	$1,319	$2,020	$10,850	$47,432
2022	11	4,711	12,536	$14,850			$14,850	$25,648	$6,909	$1,323	$1,981	$10,850	$46,711
2023	14	4,748	12,350	$18,900			$18,900	$25,268	$6,807	$1,333	$1,975	$10,850	$46,233
2024	0	4,660	12,472	$0			$0	$25,516	$6,874	$1,311	$1,955	$10,850	$46,506
2025	0	4,632	12,340	$0			$0	$25,247	$6,801	$1,305	$1,948	$10,850	$46,151
2026	0	4,257	11,416	$0			$0	$23,357	$6,292	$1,215	$1,844	$10,850	$43,558
2027	0	2,790	8,461	$0			$0	$17,312	$4,664	$863	$1,365	$10,850	$35,053
2028	0	2,066	6,009	$0			$0	$12,293	$3,312	$690	$983	$10,850	$28,128
2029	0	1,340	4,135	$0			$0	$8,460	$2,279	$516	$692	$26,950	$38,897
Totals	322	46,895,053	124,323,334	$434,700	$60,105	$180,000	$674,805	$696,870	$187,728	$36,629	$53,936	$341,600	$1,316,764

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 45 m Net Pay Thickness

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m³/d)	Steam Injection (m³/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$63	$235	$298						
1997	11			$14,850	$86	$319	$15,254						
1998	11			$14,850	$20,958	$78,072	$113,879						
1999	10			$13,500	$21,497	$80,082	$115,079						
2000	9	2,777	4,413	$12,150	$5,716	$21,293	$39,159	$9,029	$2,432	$860	$659	$10,850	$23,831
2001	9	4,510	7,772	$12,150			$12,150	$15,901	$4,283	$1,275	$1,191	$10,850	$33,501
2002	9	4,483	8,741	$12,150			$12,150	$17,884	$4,818	$1,269	$1,332	$10,850	$36,152
2003	9	4,633	8,262	$12,150			$12,150	$16,904	$4,554	$1,305	$1,252	$10,850	$34,865
2004	9	4,719	8,669	$12,150			$12,150	$17,737	$4,778	$1,326	$1,276	$10,850	$35,967
2005	9	4,666	9,516	$12,150			$12,150	$19,470	$5,245	$1,313	$1,404	$10,850	$38,282
2006	9	4,707	10,117	$12,150			$12,150	$20,698	$5,576	$1,323	$1,488	$10,850	$39,934
2007	9	4,693	9,990	$12,150			$12,150	$20,439	$5,506	$1,319	$1,463	$10,850	$39,577
2008	9	4,688	10,373	$12,150			$12,150	$21,223	$5,717	$1,318	$1,516	$10,850	$40,624
2009	3	4,697	10,598	$4,050			$4,050	$21,684	$5,841	$1,320	$1,556	$10,850	$41,251
2010	0	4,708	10,670	$0			$0	$21,830	$5,881	$1,323	$1,567	$10,850	$41,451
2011	0	4,657	10,461	$0			$0	$21,402	$5,766	$1,311	$1,585	$10,850	$40,913
2012	0	4,172	9,723	$0			$0	$19,893	$5,359	$1,194	$1,647	$10,850	$38,943
2013	0	4,031	8,372	$0			$0	$17,128	$4,614	$1,161	$1,606	$10,850	$35,359
2014	0	4,525	7,723	$0			$0	$15,801	$4,257	$1,279	$1,284	$10,850	$33,470
2015	0	4,701	7,795	$0			$0	$15,947	$4,296	$1,321	$1,373	$10,850	$33,787
2016	0	4,673	8,494	$0			$0	$17,379	$4,682	$1,315	$1,479	$10,850	$35,703
2017	0	4,513	8,643	$0			$0	$17,682	$4,763	$1,276	$1,448	$10,850	$36,020
2018	0	4,658	8,320	$0			$0	$17,022	$4,586	$1,311	$1,403	$10,850	$35,172
2019	0	4,717	8,189	$0			$0	$16,755	$4,514	$1,325	$1,360	$10,850	$34,804
2020	0	4,703	8,279	$0			$0	$16,938	$4,563	$1,322	$1,383	$10,850	$35,056
2021	0	4,658	8,533	$0			$0	$17,458	$4,703	$1,311	$1,394	$10,850	$35,717
2022	0	4,676	8,777	$0			$0	$17,958	$4,838	$1,315	$1,401	$10,850	$36,362
2023	0	4,712	8,813	$0			$0	$18,030	$4,857	$1,324	$1,389	$10,850	$36,450
2024	0	4,663	8,978	$0			$0	$18,368	$4,978	$1,312	$1,387	$10,850	$36,866
2025	0	4,521	9,166	$0			$0	$18,753	$5,052	$1,278	$1,379	$10,850	$37,313
2026	0	3,964	8,585	$0			$0	$17,565	$4,732	$1,145	$1,286	$10,850	$35,577
2027	0	3,538	7,880	$0			$0	$16,121	$4,343	$1,043	$1,196	$10,850	$33,553
2028	0	2,992	6,865	$0			$0	$14,046	$3,784	$912	$1,114	$10,850	$30,706
2029	0	2,711	6,076	$0			$0	$12,432	$3,349	$844	$1,053	$16,650	$34,329
Totals	116	47,838,484	94,460,307	$156,600	$48,320	$180,000	$384,920	$529,478	$142,635	$37,248	$40,873	$331,300	$1,081,535

Appendix 3

Overlying Water Effect Data Set and Results, Commercial Plant Utilization and Detailed Plant Bitumen Forecasts and Undiscounted Costs for Athabasca McMurray

```
** SOURCE DATA SET: ATHABASCA MCMURRAY CASE STUDY -
** EFFECT OF OVERLYING WATER SANDS
** CMG STARS SIMULATION
**
** No Gas Cap, only an oerlying Water Zone (80% Water / 20% Bitumen)
** Thickness of Water Sands Zone is 5 m, and
** The Thickness of the Bitumen Pay is 24 m
** 3D run assuming a Dead Oil @ Reservoir Conditions
** Model Dimensions: 549 m x 500 m x 29
** Initial Reservoir Pressure = 1800 kPa
** Full scale pattern simulation with 3 Well Pairs
** Inter-Well Distance is 90 m
** (Well Pair 1 assumes perfect symmetry)
** Grid Block thickness is variable in i-direction (115 - 2 m, 63 - 5 m and
** 2 - 2 m grid thickness), j-direction consists of two slabs -j1 is 100 m and
** the poorer j2 is 400 m, and k-direction consists of a constants 2 m thickness
** There is a "SINK" Well located in the upper right-most corner
** of the model to allow for Stystem Back Pressure
** Input and Output Units are SI; and time basis is days
**
** --------------  INPUT/OUTPUT  -----------------------

*filename   *output 'Athabasca_5m_Overlying_Water_Sands_1800kPa.out' *index-out
*main-results-out

*title1 'Joint ADOE-EUB SAGD Study'
*title2 'Case Study: Effect of Overlying Water Sands in a 5m Water Cap at High P
ressure'
*title3 'Pattern Simulation'

**restart

*maxerror 1
*wrst *time

*prntorien  2  0
*outprn *grid *pres *temp *sw *so *x *y
*outprn *well *brief
*wsrf *grid *time
*outsrf *grid *pres *temp *sw *so *x *y
*outprn *iter *newton
*xdr on
*wprn *iter *time
```

```
** ----------  GRID AND RESERVOIR DEFINITION ----------

*grid *cart 180 2 14

*kdir *up

*di *ivar 115*2.0 63*5.0 2*2.0

*dj *jvar   100.  400.

*dk *kvar 12*2.0  2*2.5

*vamod 2 0.5 1.0 0.5 0.5 *9p 1.0 1.0
*vatype *ivar 2 179*1

*dtop *con 140.0

*por *ijk
1:180  1  1:7      0.35
1:180  1  8:12     0.30
1:180  1  13:14    0.30
1:180  2  1:3      0.35
1:180  2  4        0.30
1:180  2  5        0.35
1:180  2  6        0.30
1:180  2  7:8      0.35
1:180  2  9:12     0.30
1:180  2  13:14    0.30

*permi *ijk
1:180  1  1:7      10000
1:180  1  8:12     2000
1:180  1  13:14    2000
1:180  2  1:3      10000
1:180  2  4        2000
1:180  2  5        10000
1:180  2  6        2000
1:180  2  7:8      10000
1:180  2  9:12     2000
1:180  2  13:14    2000

*permj *ijk
1:180  1  1:7      10000
1:180  1  8:12     2000
1:180  1  13:14    2000
1:180  2  1:3      10000
1:180  2  4        2000
1:180  2  5        10000
1:180  2  6        2000
1:180  2  7:8      10000
1:180  2  9:12     2000
1:180  2  13:14    2000

*permk *ijk
1:180  1  1:7      5000
1:180  1  8:12     200
1:180  1  13:14    200
1:180  2  1:3      2500
```

```
1:180  2  4      200
1:180  2  5      2500
1:180  2  6      200
1:180  2  7:8    2500
1:180  2  9:12   200
1:180  2  13:14  200

*cpor 7.0e-6 *prpor 100.0

*rockcp 2.390e6
*cpo    17.0
*thconr 1.469e5
*thconw 1.469e5
*thcono 1.469e5

*hlossprop *overbur 2.390e6 1.469e5 *hlosst 7.0 *hlosstdiff 0.1
*hlossprop *underbur 2.390e6 2.333e5 *hlosst 7.0 *hlosstdiff 0.1

** ==============  FLUID DEFINITIONS  ================

*model 2 2 2

*compname      'WATER'      'OIL'
**          -------------------------
*cmm            0          0.5
*pcrit          0          0
*tcrit          0          0

*molden         0          2020.0
*cp             0          6.84e-7
*ct1            0          7.85e-4
*ct2            0          0

*kv1            0          0
*kv2            0          0
*kv3            0          0
*kv4            0          0
*kv5            0          0

*cpl1           0          1000.0
*cpg1           0          841.0
*hvapr          0          1346.0
```

```
*visctable

**  Temp
    10.0        0          0.17e7
    20.0        0          0.319e6
    40.0        0          0.223e5
    60.0        0          3073.0
    80.0        0          680.6
   100.0        0          212.63
   120.0        0          85.54
   140.0        0          41.57
   160.0        0          23.32
   180.0        0          14.60
   200.0        0          9.96
   220.0        0          7.26
   240.0        0          5.59
   260.0        0          4.49
   280.0        0          3.73
```

File: Athabasca 6m Water Sands 1800kPa.dat 2

```
** ==================  ROCK-FLUID DATA  ==============

*rockfluid

*rpt 1

*swt

**  Sw          Krw          Krow
** ------------------------------
    0.1500     0.0000      0.9920
    0.2000     0.200e-3    0.9790
    0.2500     0.160e-2    0.9500
    0.3000     0.550e-2    0.7200
    0.3500     0.130e-1    0.6000
    0.4000     0.254e-1    0.4700
    0.4500     0.440e-1    0.3500
    0.5000     0.698e-1    0.2400
    0.5500     0.1040      0.1650
    0.6000     0.1480      0.0930
    0.6500     0.2040      0.0700
    0.7000     0.2710      0.0400
    0.7500     0.3520      0.0150
    0.8000     0.4470      0.0000
    0.8500     0.5590      0.0000
    0.9000     0.6870      0.0000
    0.9500     0.8340      0.0000
    1.0000     1.0000      0.0000

*slt

**  Sl          Krg          Krog
** ------------------------------
    0.1500     1.0000      0.0000
    0.2000     0.9500      0.200-3
    0.2500     0.8400      0.160e-2
    0.3000     0.7200      0.550e-2
    0.3500     0.6000      0.130e-1
    0.4000     0.4700      0.254e-1
    0.4500     0.3500      0.440e-1
    0.5000     0.2400      0.698e-1
    0.5500     0.1650      0.1040
    0.6000     0.930e-1    0.1480
    0.6500     0.750e-1    0.2040
    0.7000     0.450e-1    0.2710
    0.7500     0.270e-1    0.3520
    0.8000     0.200e-1    0.4470
    0.8500     0.100e-1    0.5590
    0.9000     0.500e-2    0.6870
    0.9500     0.0000      0.8340
    1.0000     0.0000      0.9920
```

```
*rpt 2

*swt

**  Sw        Krw         Krow
** ----------------------------
    0.25      0.0         0.95
    0.3       0.0005      0.72
    0.35      0.003       0.6
    0.4       0.009       0.47
    0.45      0.022       0.35
    0.5       0.046       0.24
    0.55      0.081       0.165
    0.6       0.131       0.093
    0.65      0.186       0.07
    0.7       0.257       0.04
    0.75      0.341       0.015
    0.8       0.436       0.
    0.85      0.551       0.
    0.9       0.683       0.
    0.95      0.832       0.
    1.0       1.0         0.

*slt

**  Sl        Krg         Krog
** ----------------------------
    0.25      0.84        0.
    0.3       0.72        0.0005
    0.35      0.6         0.003
    0.4       0.47        0.009
    0.45      0.35        0.022
    0.5       0.24        0.046
    0.55      0.165       0.081
    0.6       0.093       0.131
    0.65      0.075       0.186
    0.7       0.045       0.257
    0.75      0.027       0.341
    0.8       0.02        0.436
    0.85      0.01        0.551
    0.9       0.005       0.683
    0.95      0.          0.832
    1.0       0.          0.95

*krtype *ijk
1:180  1  1:7        1
1:180  1  8:12       2
1:180  1  13:14      2
1:180  2  1:3        1
1:180  2  4          2
1:180  2  5          1
1:180  2  6          2
1:180  2  7:8        1
1:180  2  9:12       2
1:180  2  13:14      2
```

File: Athabasca 5m Water Sands 1800kPa.dat 3

```
** ----------------  INITIAL CONDITIONS  -------------------

*initial

*pres *con 1800.0

*temp *con 7.0

*so *ijk
1:180  1  1:7        0.85
1:180  1  8:12       0.75
1:180  1  13:14      0.20
1:180  2  1:3        0.85
1:180  2  4          0.75
1:180  2  5          0.85
1:180  2  6          0.75
1:180  2  7:8        0.85
1:180  2  9:12       0.75
1:180  2  13:14      0.20


*molefrac *oil *con  0.0  1.0

** ----------------  NUMERICAL CONTROL  --------------------

*numerical

*aim            *stab    **was off
*dtmax          15.0
*maxsteps       50000
*north          8
*itermax        60
*unrelax        -1
*sdegree        2
*sorder         rcmrb
*mintemp        1
*minpres        50
*norm           *press 400.0
                *satur 0.2
                *temp 50.      *y      0.2     *x      0.2

*converge       *press 30.
                *satur 0.04    *y      .04     *x      .04
                *temp . 3.0

*pvtoscmax      4
```

```
** --------------  RECURRENT DATA  -------------------------

*run

*date 2000 1 1  *dtwell 1.0e-2

*well 1 'INJ1'  *frac   0.5
*injector *mobweight 1
*tinjw 226.0  *qual 0.95
*operate *max *bhp 2600.0
*operate *max *water 400.
*operate *max *bhp 2600.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 1
1  1:2  3
*uhtr *ijk
1:1  1:2  3     0.110e9
*tmpset *ijk
1:1  1:2  3    226.0

*well 2 'PROD1'  *frac   0.5
*producer 2
*operate *min *bhp 2250.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 2
1  1:2  1
*uhtr *ijk
1:1  1:2  1     0.110e9
*tmpset *ijk
1:1  1:2  1     218.0
```

File: Athabasca 5m Water Sands 1800kPa.dat 4

```
*well 3 'INJ2'
*injector *mobweight 3
*tinjw 226.0  *qual 0.95
*operate *max *bhp 2600.0
*operate *max *water 400.
*operate *max *bhp 2600.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 3
46  1:2  3
*uhtr *ijk
46:46  1:2  3     0.110e9
*tmpset *ijk
46:46  1:2  3     226.0

*well 4 'PROD2'
*producer 4
*operate *min *bhp 2250.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 4
46  1:2  1
*uhtr *ijk
46:46  1:2  1     0.110e9
*tmpset *ijk
46:46  1:2  1     218.0
```

```
*well 5 'INJ3'
*injector *mobweight 5
*tinjw 226.0  *qual 0.95
*operate *max *bhp 2600.0
*operate *max *water 400.
*operate *max *bhp 2600.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 5
91  1:2  3
*uhtr *ijk
91:91  1:2  3     0.110e9
*tmpset *ijk
91:91  1:2  3     226.0

*well 6 'PROD3'
*producer 6
*operate *min *bhp 2250.0
*operate *max *steam 0.5
*operate *max *liquid 800.0
*geometry *j 0.110 0.249 1.0  0.0
*perf *geo 6
91  1:2  1
*uhtr *ijk
91:91  1:2  1     0.110e9
*tmpset *ijk
91:91  1:2  1     218.0

*well 7 'SINK'
*producer 7
*operate *min *bhp 1800.
*geometry *j 0.110 0.249 1.0 0.0
*perf *geo 7
180  1:2  14

*group  'INJ1' 'INJ2' 'INJ3' *attachto 'INJECTION'
*group  'PROD1' 'PROD2' 'PROD3' *attachto 'PRODUCTION'
```

File: Athabasca 5m Water Sands 1800kPa.dat 5

```
*dtmax 1.0

*time 10.0
*time 20.0
*time 36.5    **0.1 yrs
*time 50.
*time 60.
*time 70.
*time 90.
*time 100.
*time 120.
*time 150.
*time 180.
*time 210.
*time 250.
*time 300.
*time 350.
*time 365.0

*uhtr *ijk 1 1 4 0
*uhtr *ijk 1 1 1 0

*uhtr *ijk 46 1 4 0
*uhtr *ijk 46 1 1 0

*uhtr *ijk 91 1 4 0
*uhtr *ijk 91 1 1 0

*time 400.
*time 420.
*time 438     **1.2 yrs
*time 455.
*time 530.
*time 584.    **1.6 yrs
*time 657.    **1.8 yrs
*time 730.              **2.0 yrs
*time 803.    **2.2 yrs
*time 876.    **2.4 yrs
*time 949.    **2.6 yrs
*time 1022.   **2.8 yrs
*time 1095.             **3.0 yrs
*time 1168.   **3.2 yrs
*time 1241.   **3.4 yrs
*time 1314.   **3.6 yrs
*time 1387.   **3.8 yrs
*time 1460.              **4.0 yrs
*time 1533.   **4.3 yrs
*time 1565.
*time 1606.   **4.4 yrs
*time 1679.   **4.6 yrs
*time 1752.   **4.8 yrs
*time 1825.             **5.0 yrs
*time 1898.   **5.2 yrs
*time 1971.   **5.4 yrs
*time 2044.   **5.6 yrs
*time 2117.   **5.8 yrs
*time 2190.             **6.0 yrs
*time 2263.   **6.2 yrs
*time 2336.   **6.4 yrs
*time 2409.   **6.6 yrs
*time 2482.   **6.8 yrs
*time 2555.             **7.0 yrs
*time 2628.   **7.2 yrs
*time 2701.   **7.4 yrs
*time 2774.   **7.6 yrs
*time 2847.   **7.8 yrs
*time 2920.             **8.0 yrs
*time 2993.   **8.2 yrs
*time 3066.   **8.4 yrs
*time 3139.   **8.6 yrs
*time 3212.   **8.8 yrs
*time 3285.             **9.0 yrs
*time 3358.   **9.2 yrs
*time 3431.   **9.4 yrs
*time 3504.   **9.6 yrs
*time 3577.   **9.8 yrs
*time 3650.             **10.0 yrs


*stop
```

File: Athabasca 5m Water Sands 1800kPa.dat 6

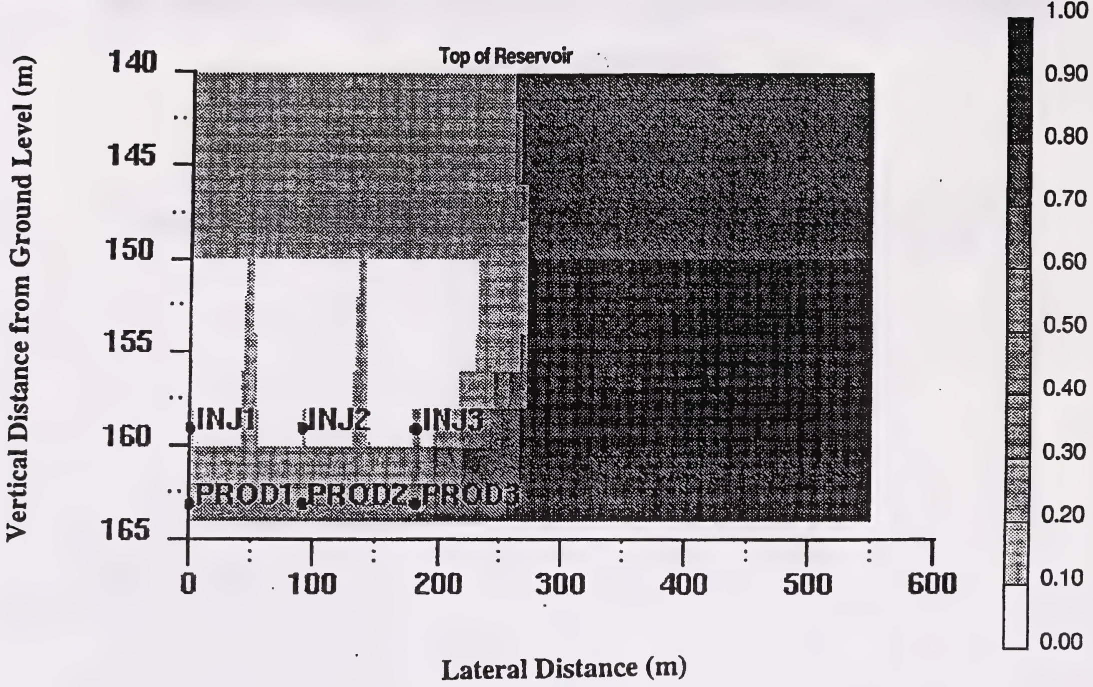
ATHABASCA McMURRAY — 0m GAS, 0m WATER at 1800 kPa

Simulation Output for:

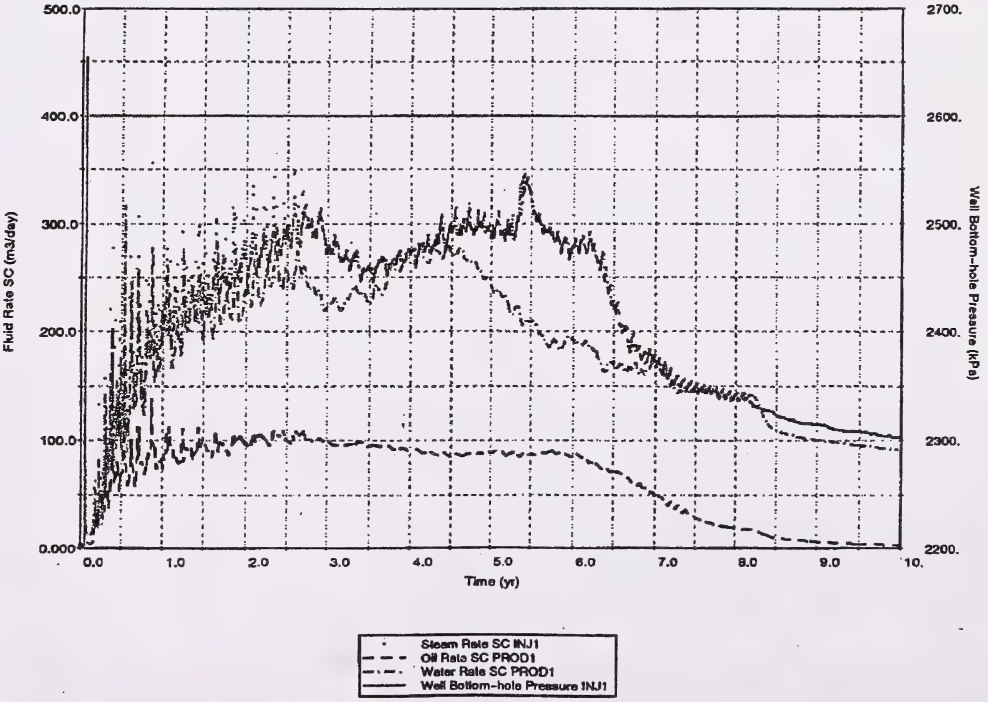
Well Pair No. 1,
Well Pair No. 2,
and Well Pair No. 3

are shown in the report, “Possible Effects of Gas Caps on SAGD Performance”

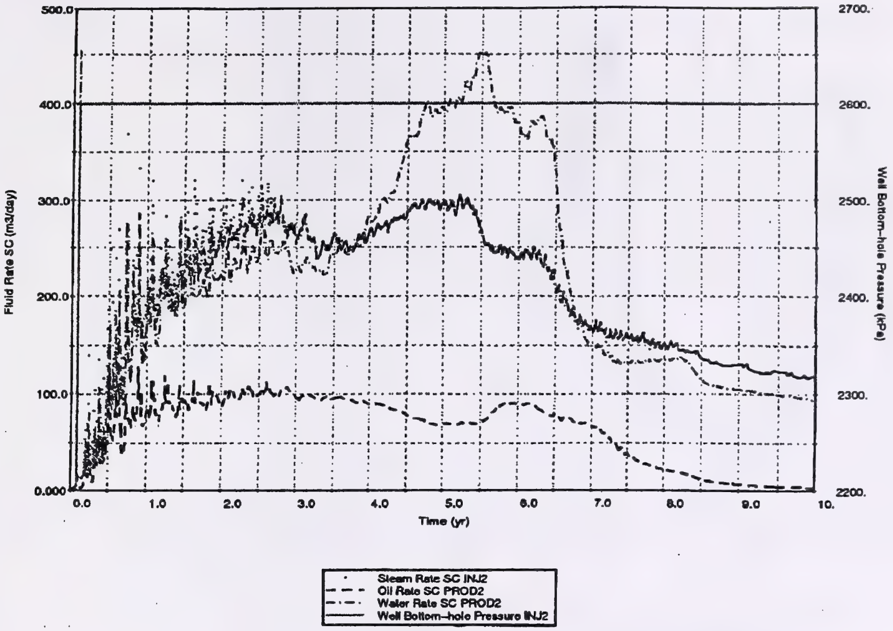
March 1997.



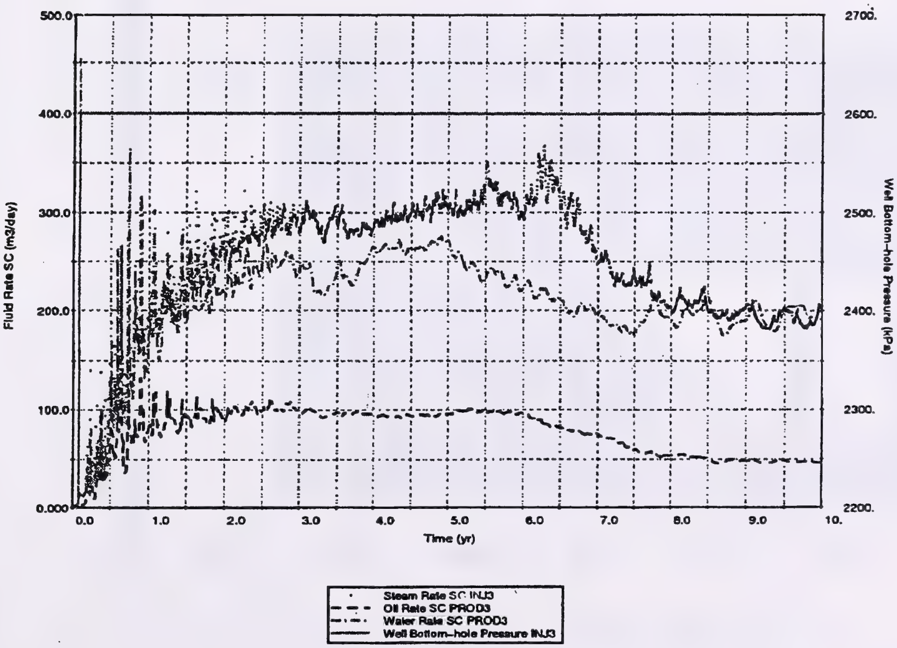
Athabasca McMurray — Reservoir Cross-Section — Base Case @ 550 kPa
Bitumen Saturation @ End of Pattern Life



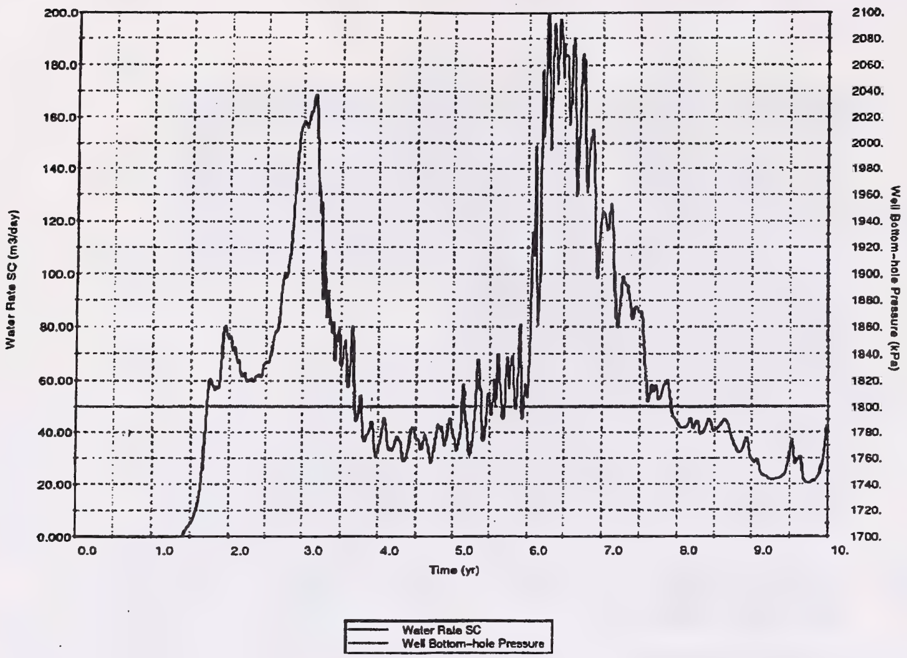
Athabasca McMurray — 5m Water Sands at 1800 kPa
Well Pair No. 1 Simulation Output



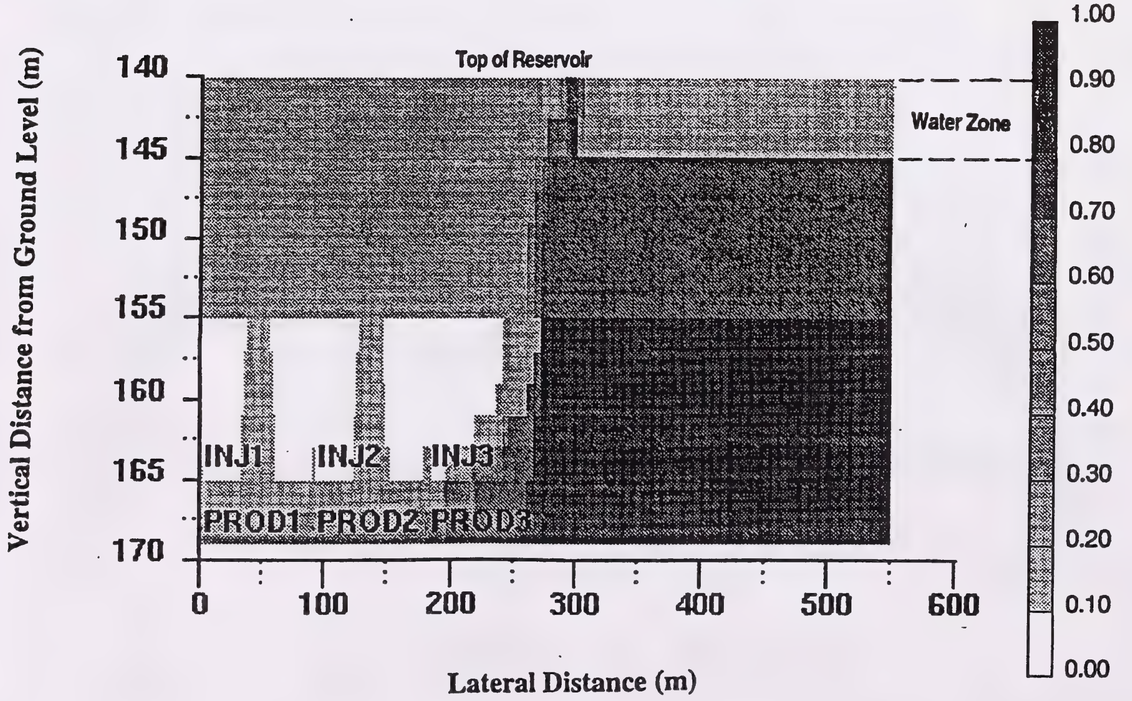
Athabasca McMurray — 5m Water Sands at 1800 kPa
Well Pair No. 2 Simulation Output



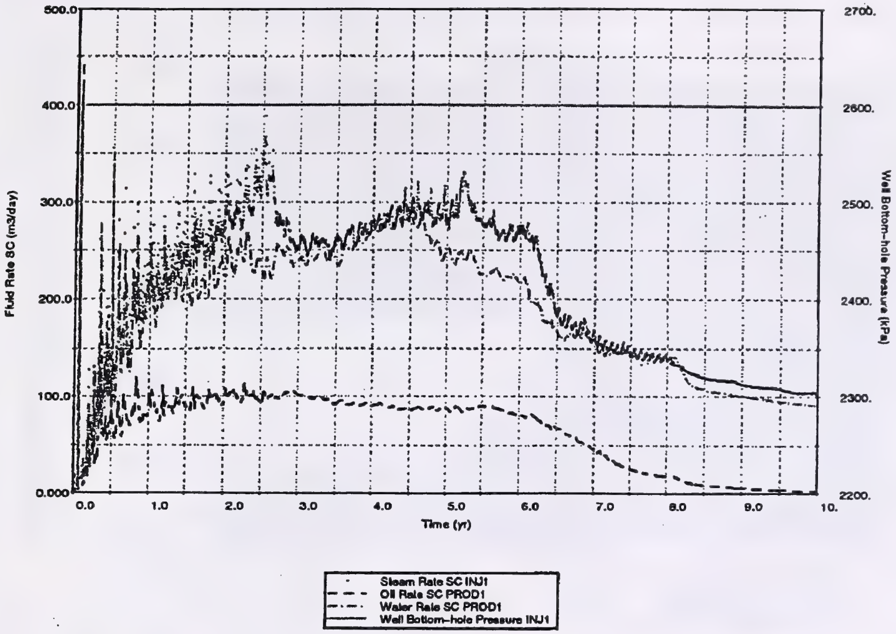
Athabasca McMurray — 5m Water Sands at 1800 kPa
Well Pair No. 3 Simulation Output



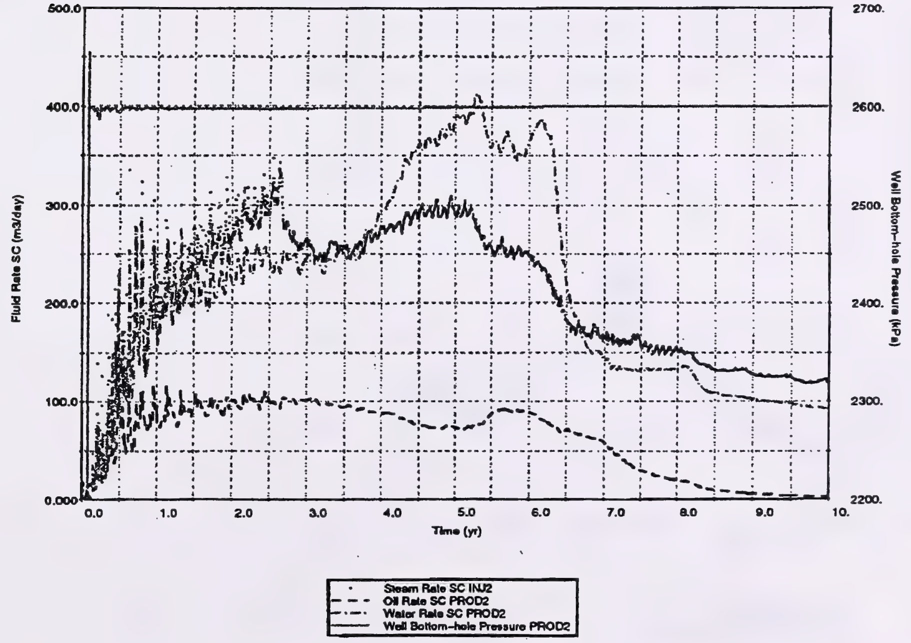
Athabasca McMurray — 5m Water Sands at 1800 kPa
Simulation Output from Pressure Sink Well



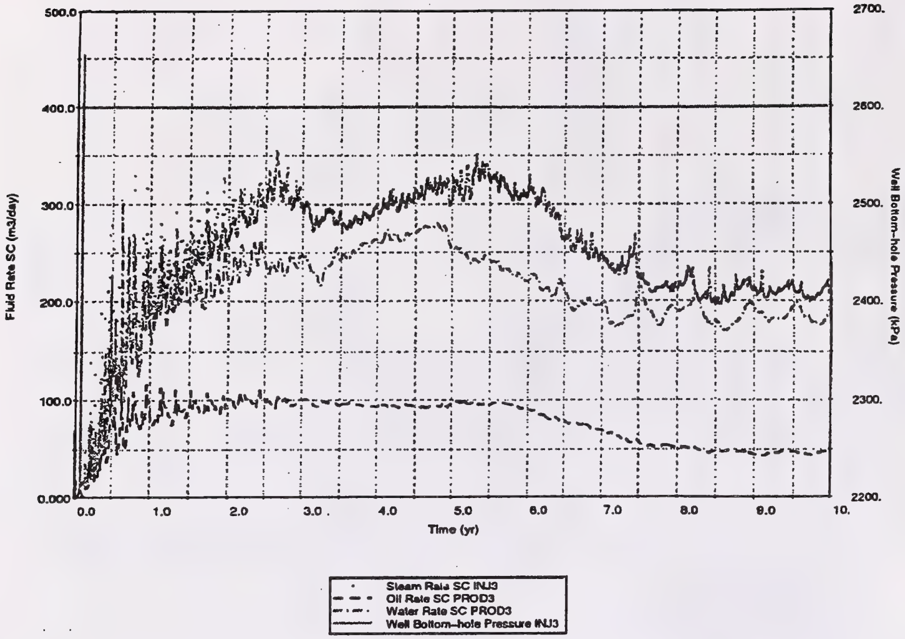
Athabasca McMurray — Reservoir Cross-Section — 5m Water Sands @ 1800 kPa
Bitumen Saturation @ End of Pattern Life



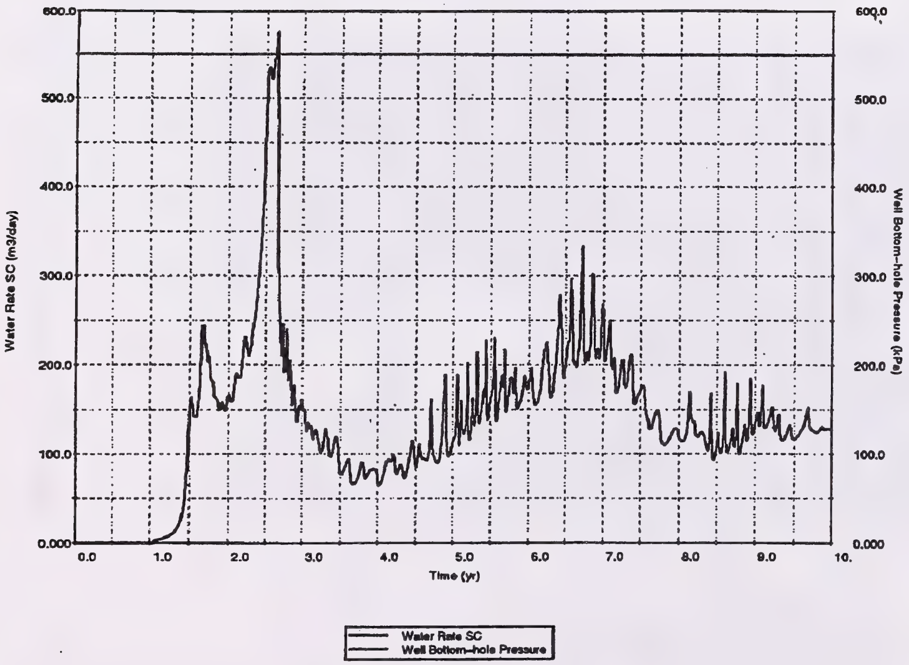
Athabasca McMurray — 5m Water Sands at 550 kPa
Well Pair No. 1 Simulation Output



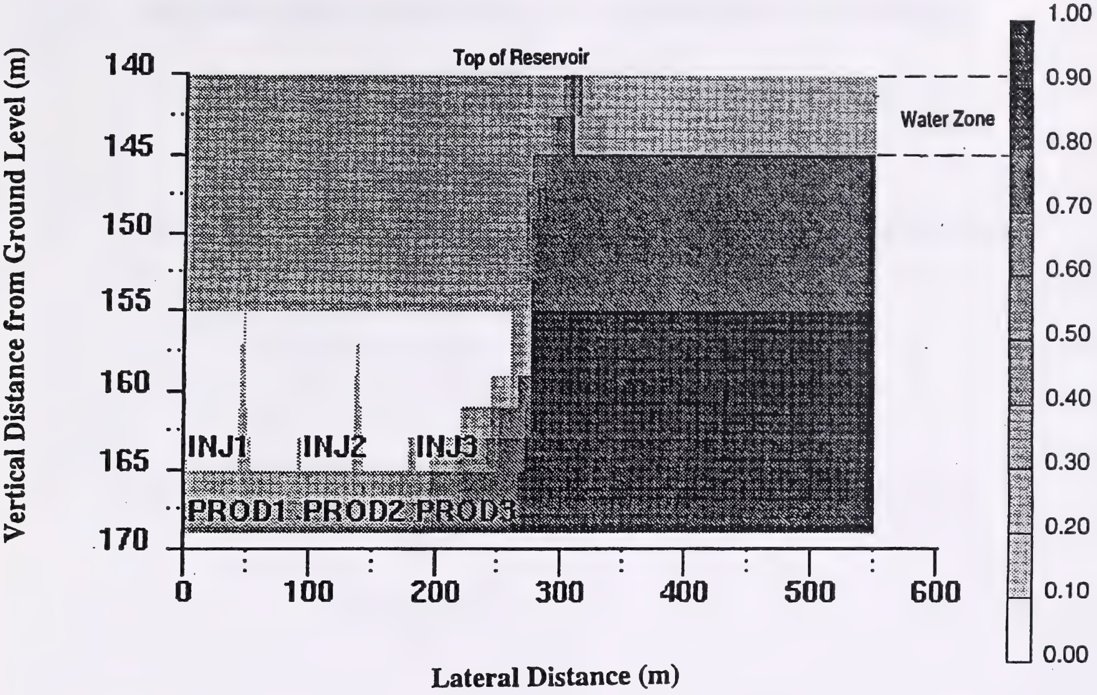
Athabasca McMurray — 5m Water Sands at 550 kPa
Well Pair No. 2 Simulation Output



Athabasca McMurray — 5m Water Sands at 550 kPa
Well Pair No. 3 Simulation Output



Athabasca McMurray — 5m Water Sands at 550 kPa
Simulation Output from Pressure Sink Well



Athabasca McMurray — Reservoir Cross-Section — 5m Water Sands @ 550 kPa
Bitumen Saturation @ End of Pattern Life

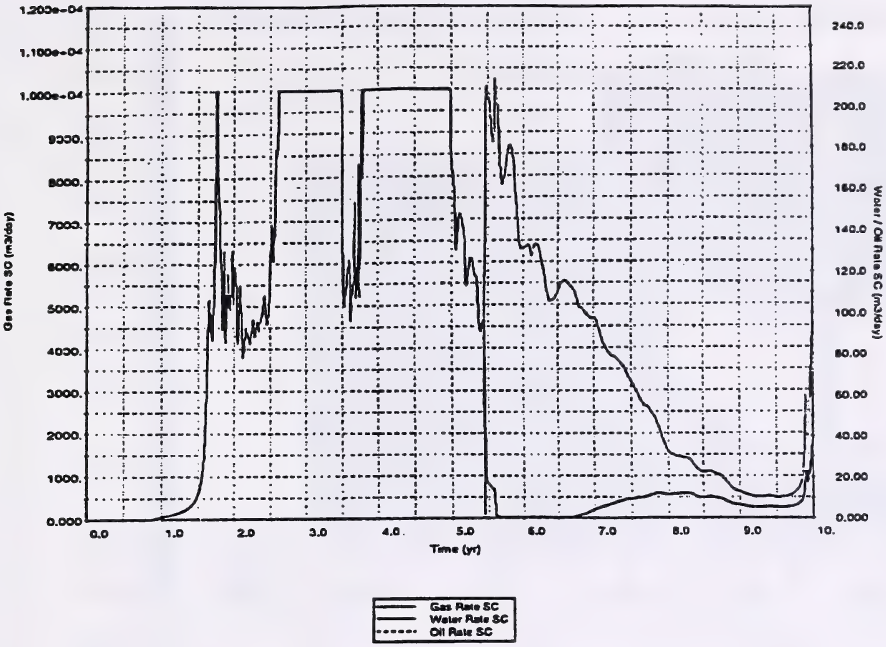
ATHABASCA McMURRAY — 5m GAS CAP at 1800 kPa

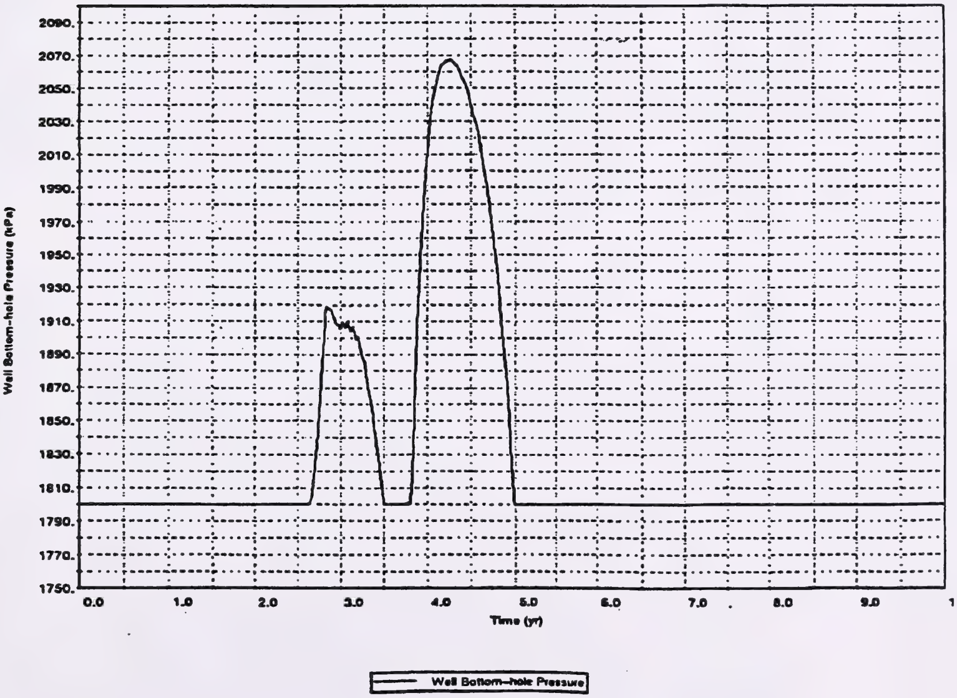
Simulation Output for:

Well Pair No. 1,
Well Pair No. 2,
and Well Pair No. 3

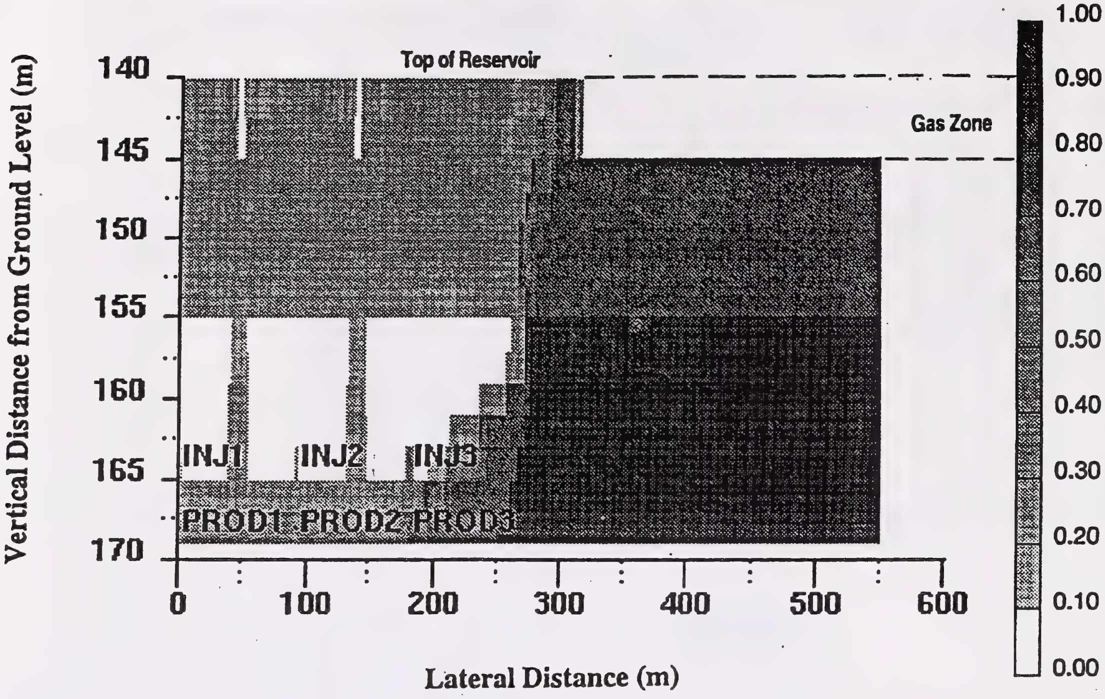
are shown in the report, “Possible Effects of Gas Caps on SAGD Performance”

March 1997.





Athabasca McMurray — 5m Non-depleted Gas Cap
Simulation Output of Gas Cap Well



Athabasca McMurray — Reservoir Cross-Section — 5m Gas Cap @ 1800 kPa
Bitumen Saturation @ End of Pattern Life

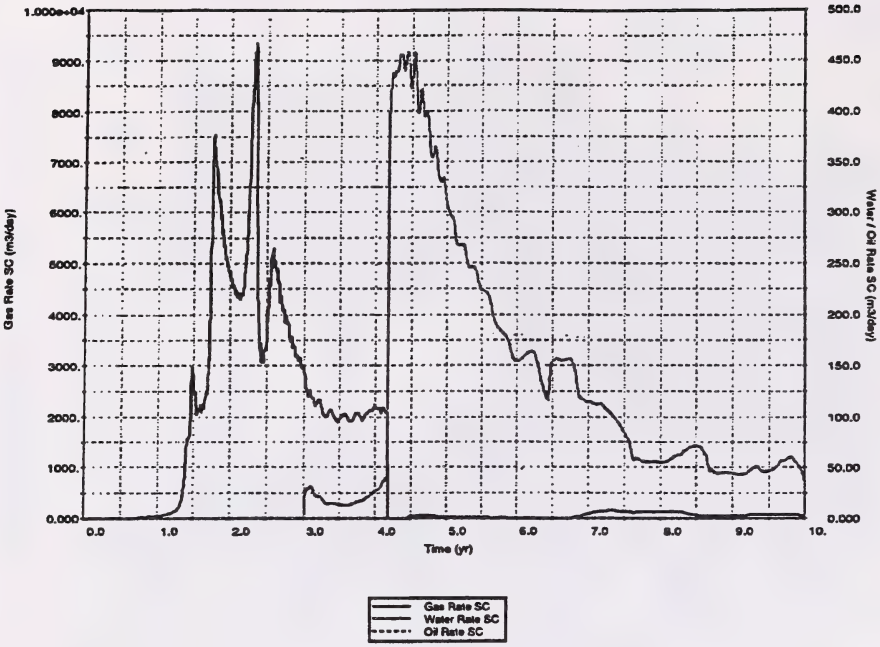
ATHABASCA McMURRAY — 5m GAS CAP at 550 kPa

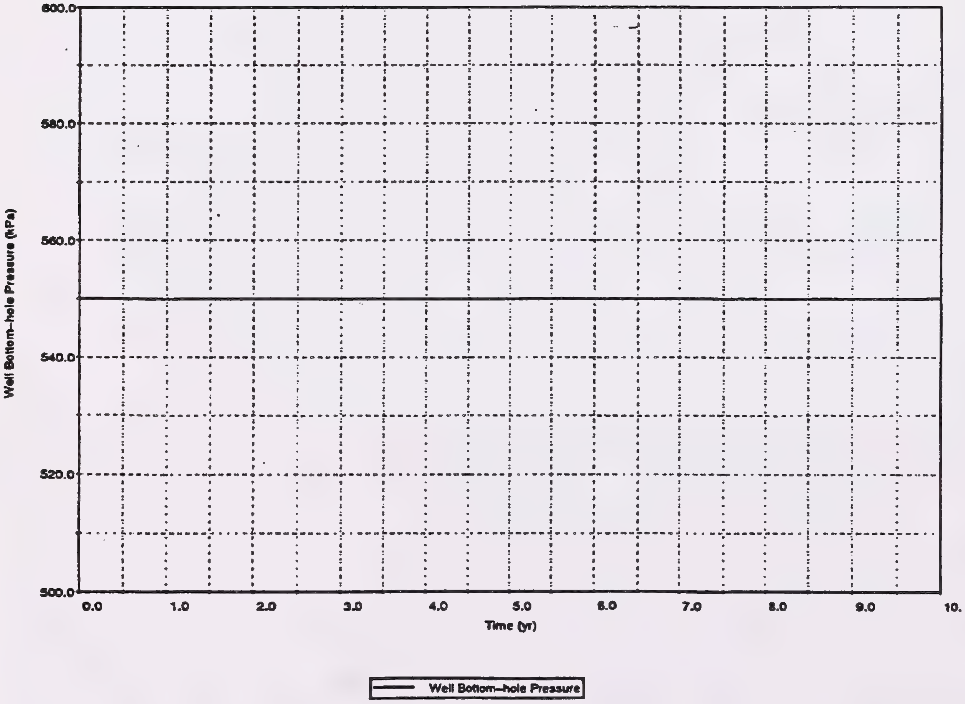
Simulation Output for:

Well Pair No. 1,
Well Pair No. 2,
and Well Pair No. 3

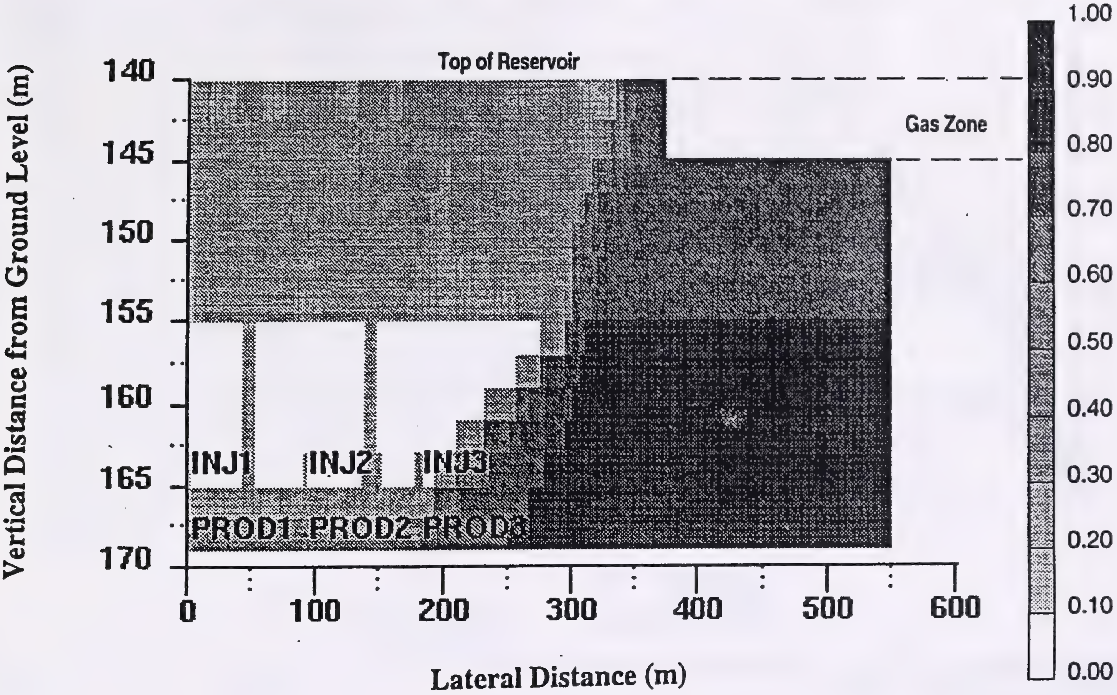
are shown in the report, "Possible Effects of Gas Caps on SAGD Performance"

March 1997.

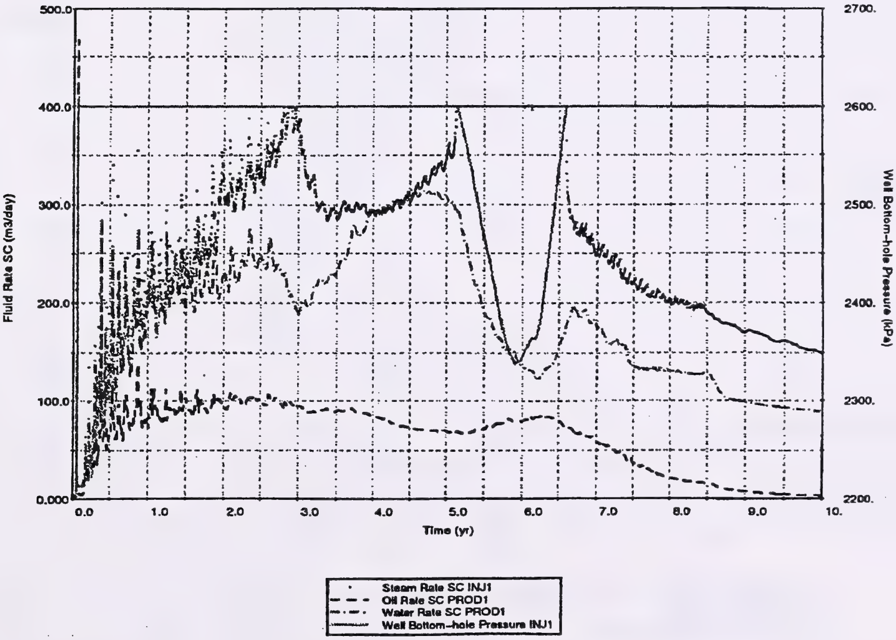




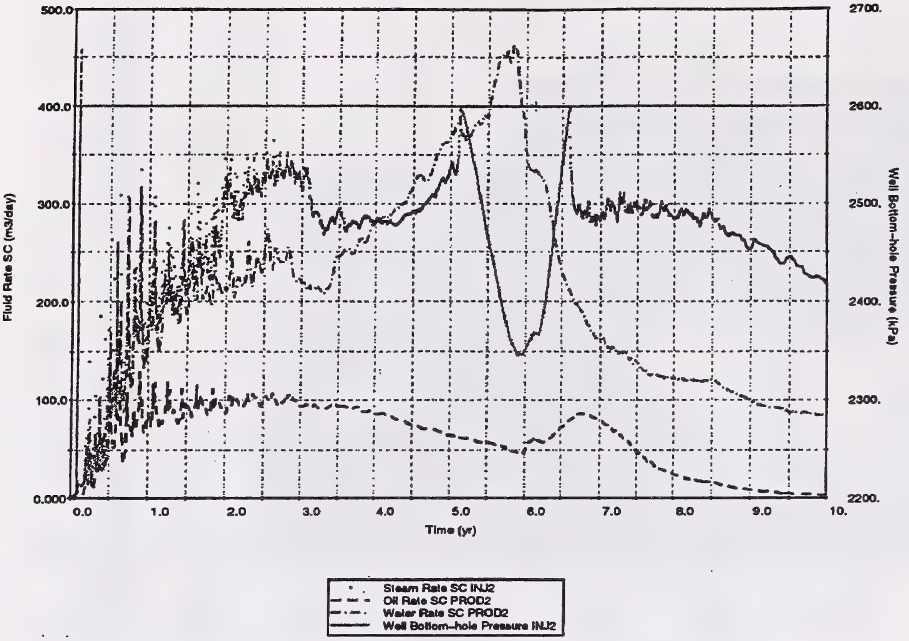
Athabasca McMurray — 5m Depleted Gas Cap
Simulation Output of Gas Cap Well



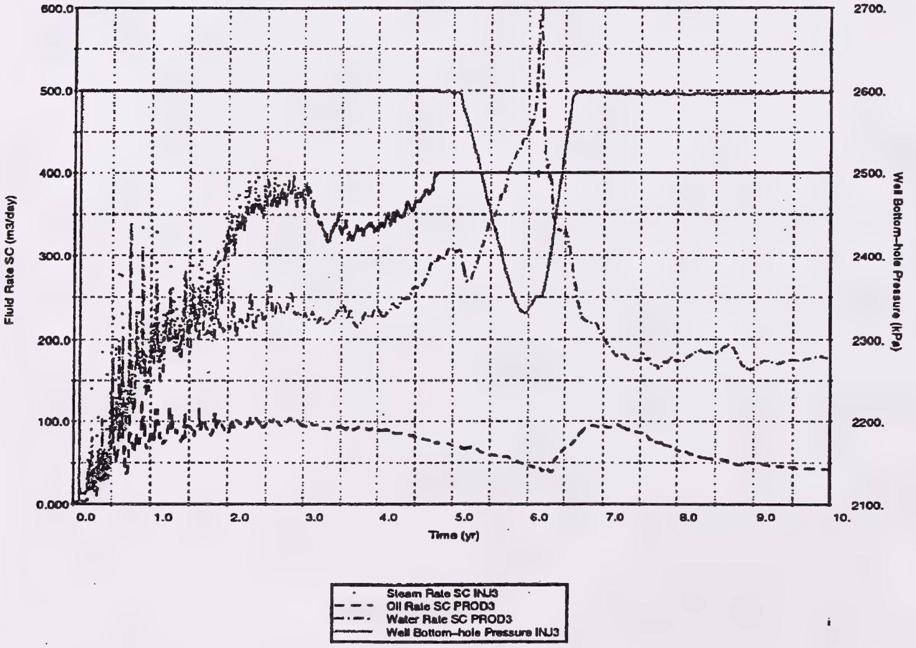
Athabasca McMurray — Reservoir Cross-Section — 5m Gas Cap @ 550 kPa
Bitumen Saturation @ End of Pattern Life



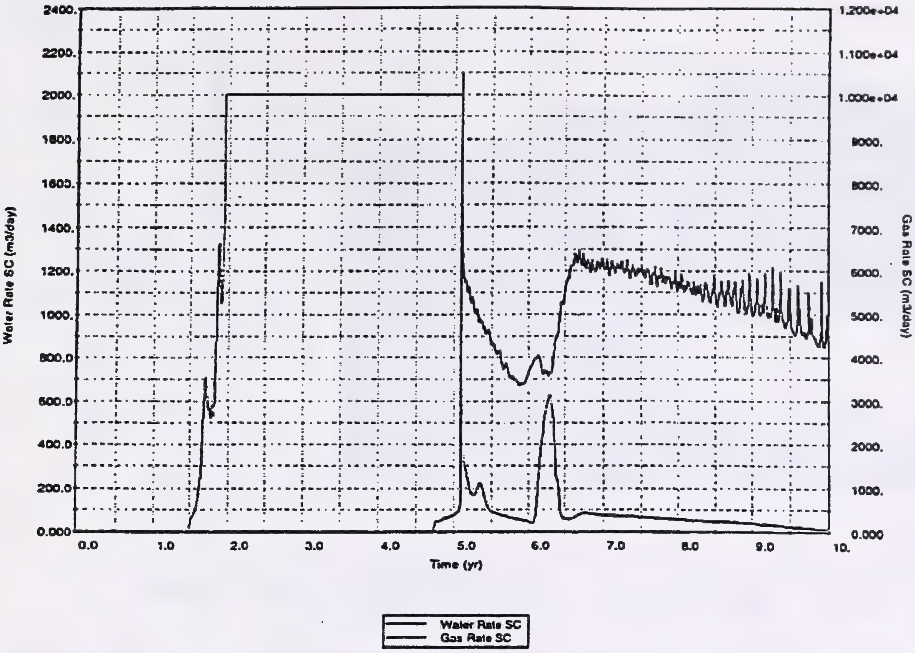
Athabasca McMurray — 5m Gas Cap & 5m Water Sands at 1800 kPa
Well Pair No. 1 Simulation Output

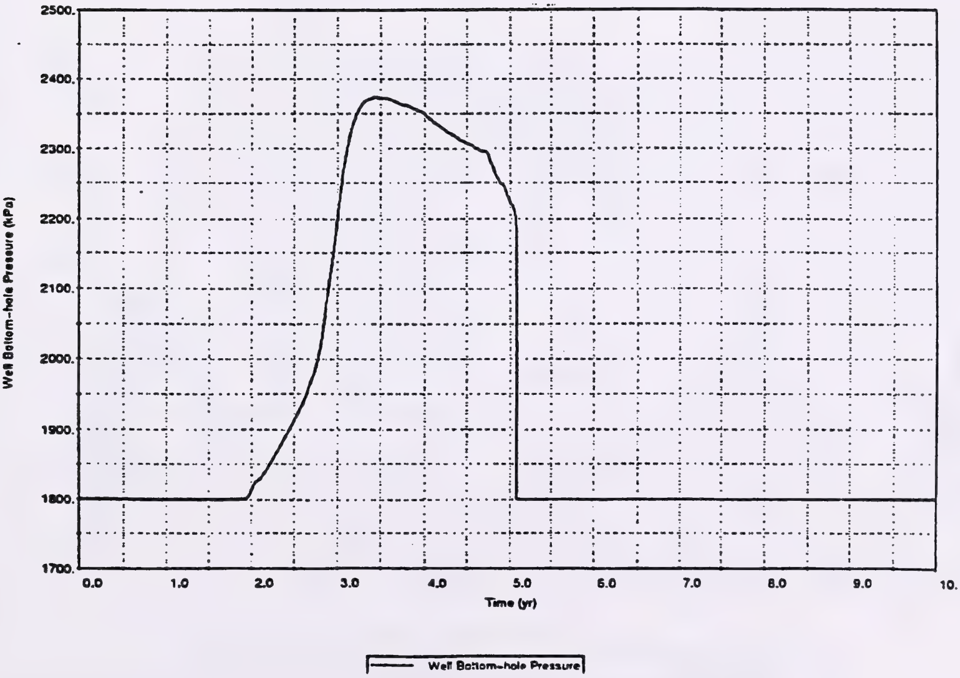


Athabasca McMurray — 5m Gas Cap & 5m Water Sands at 1800 kPa
Well Pair No. 2 Simulation Output

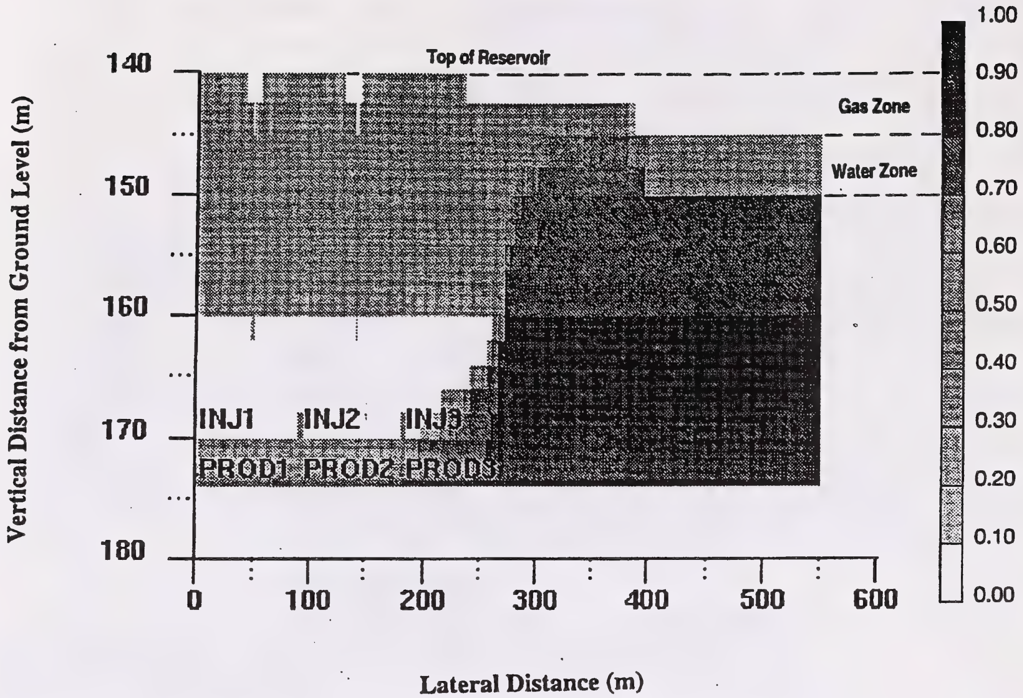


Athabasca McMurray — 5m Gas Cap & 5m Water Sands at 1800 kPa
Well Pair No. 3 Simulation Output

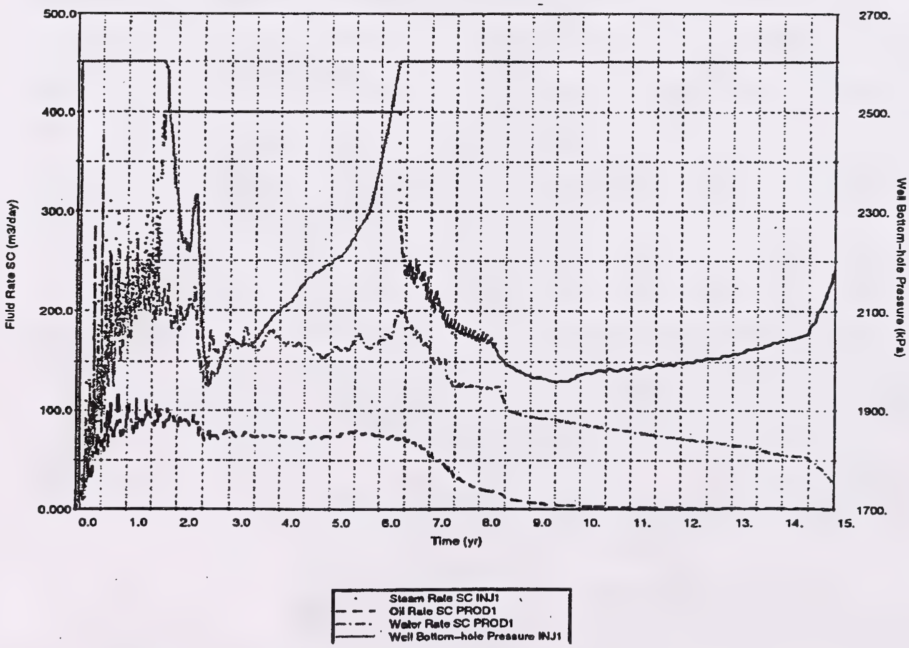




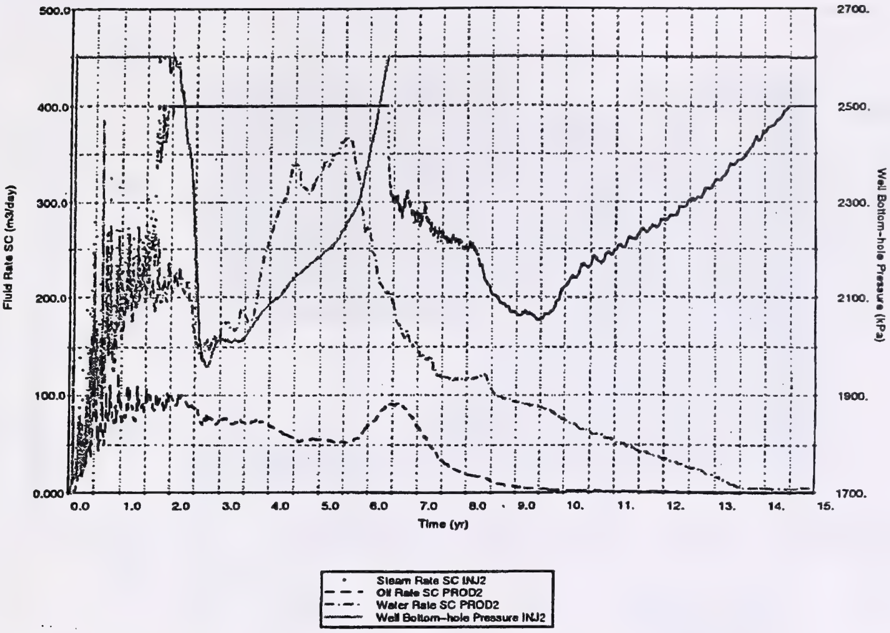
Athabasca McMurray — 5m Gas Cap & 5m Water Sands at 1800 kPa
Simulation Output from Pressure Sink Well



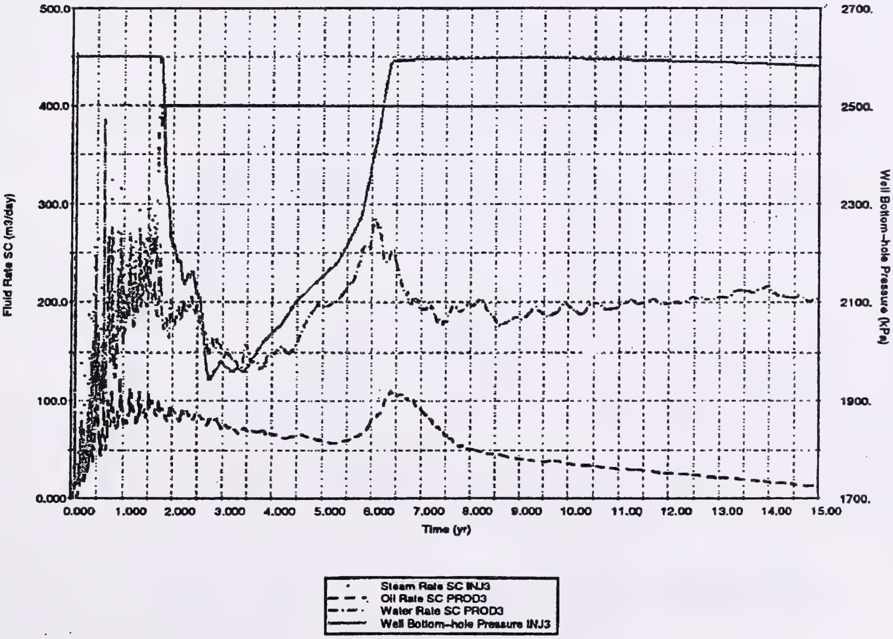
Athabasca McMurray — Reservoir Cross-Section — 5m Gas Cap & 5m Water Sands @ 1800 kPa
Bitumen Saturation @ End of Pattern Life



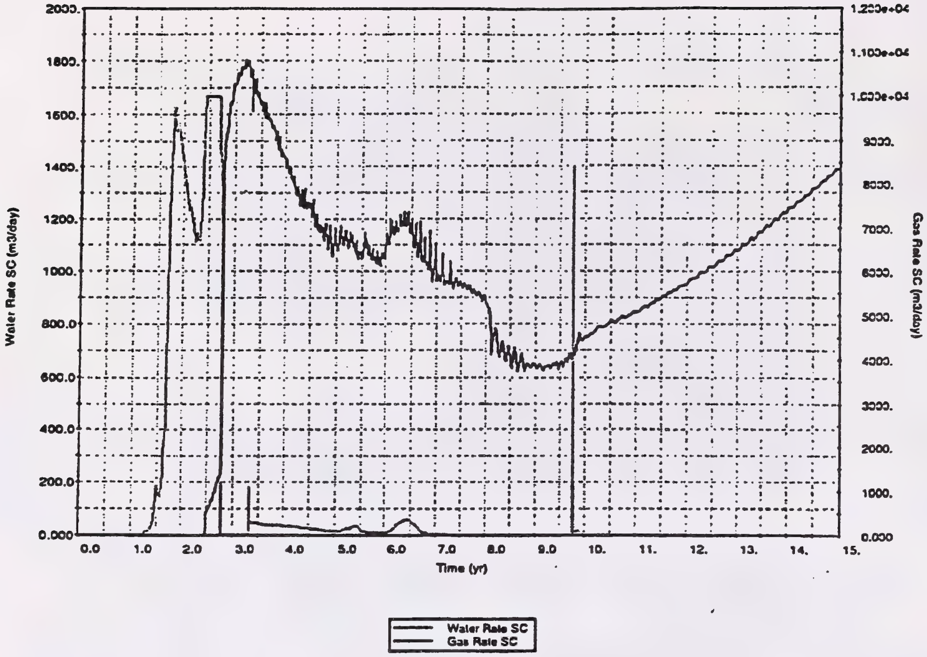
Athabasca McMurray — 5m Gas Cap & 5m Water Sands at 550 kPa
Well Pair No. 1 Simulation Output

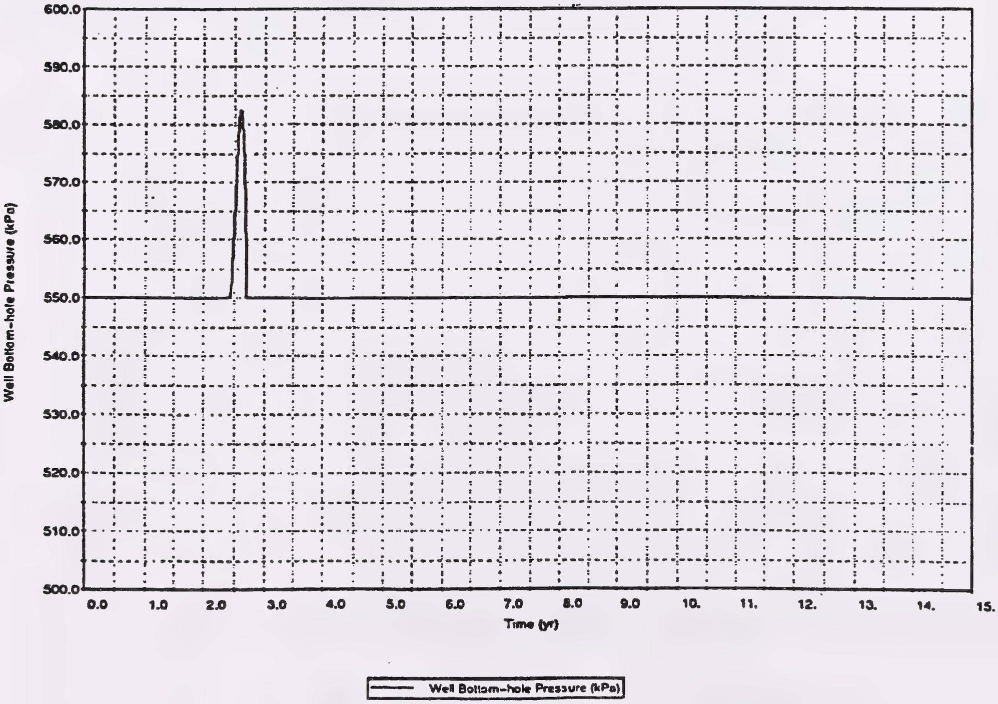


Athabasca McMurray — 5m Gas Cap & 5m Water Sands at 550 kPa
Well Pair No. 2 Simulation Output

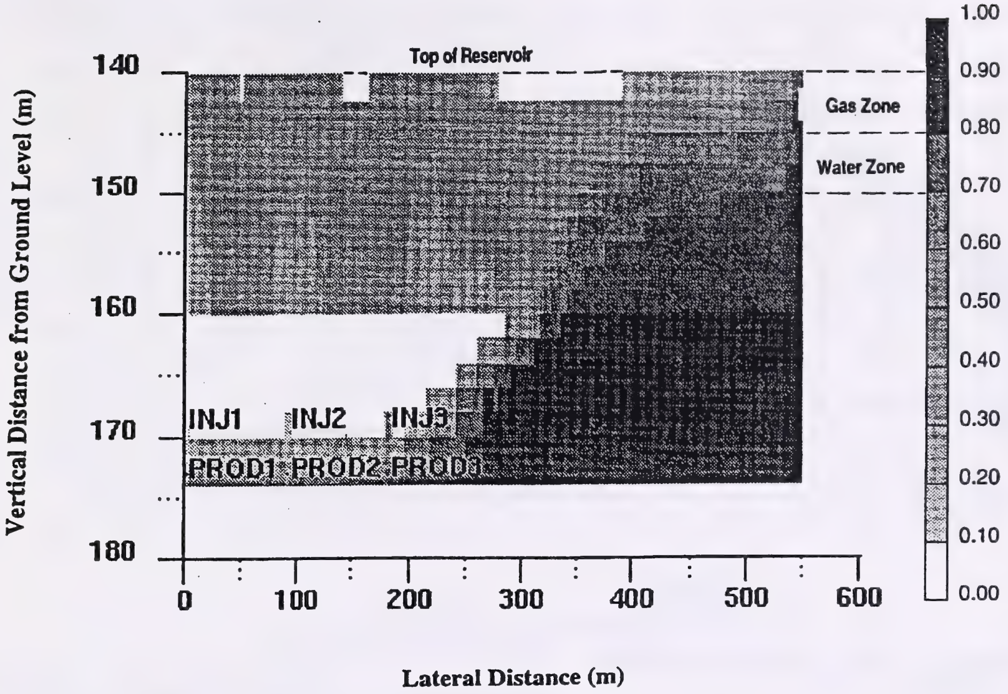


Athabasca McMurray — 5m Gas Cap & 5m Water Sands at 550 kPa
Well Pair No. 3 Simulation Output

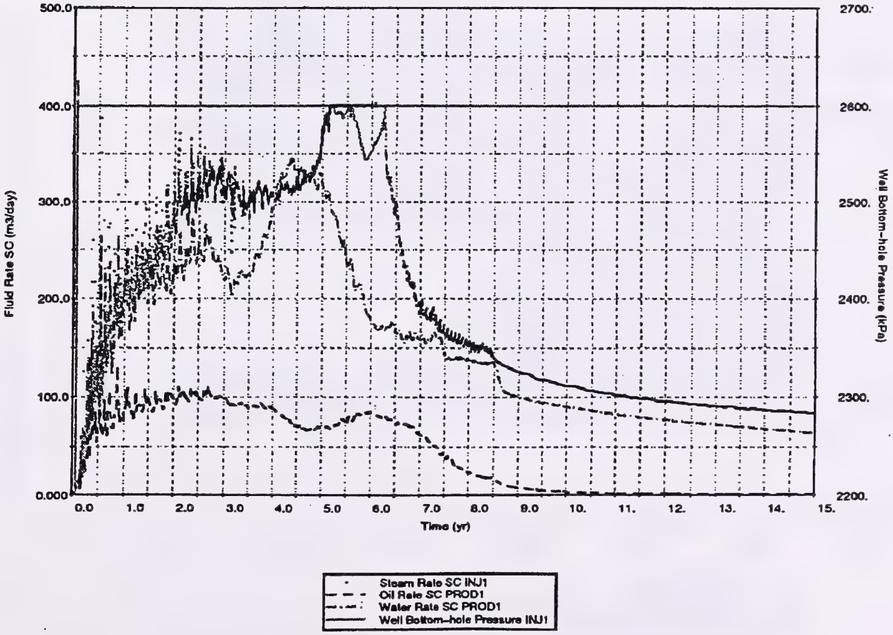




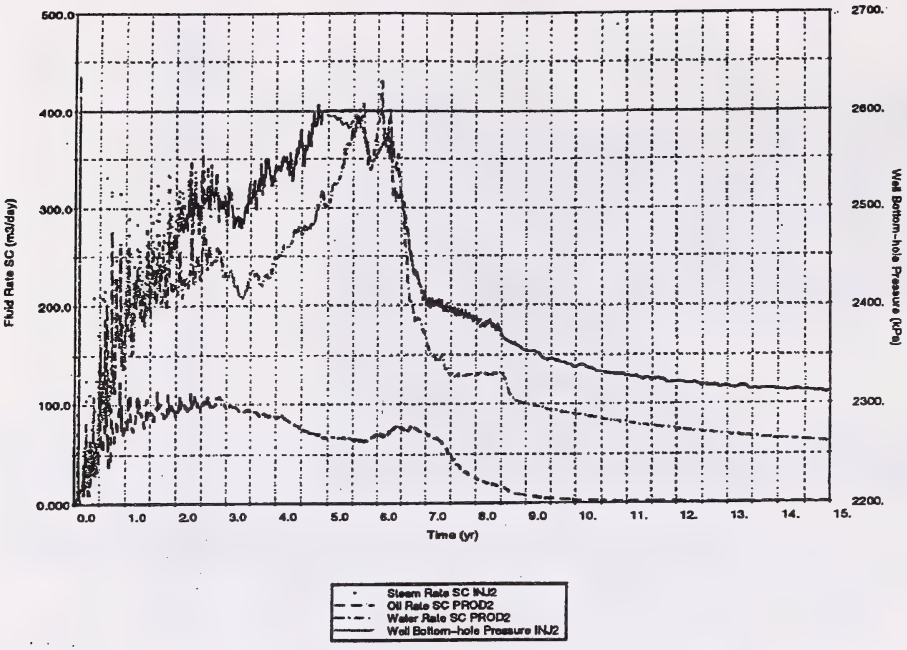
Athabasca McMurray — 5m Gas Cap & 5m Water Sands at 550 kPa
Simulation Output of Gas Cap Well



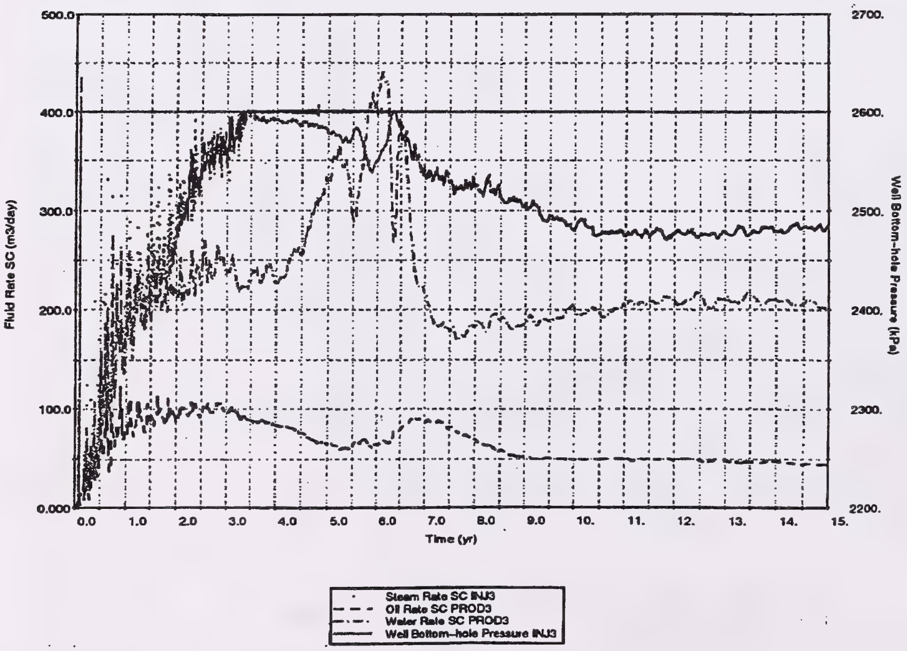
Athabasca McMurray — Reservoir Cross-Section — 5m Gas Cap & 5m Water Sands @ 550 kPa
Bitumen Saturation @ End of Pattern Life



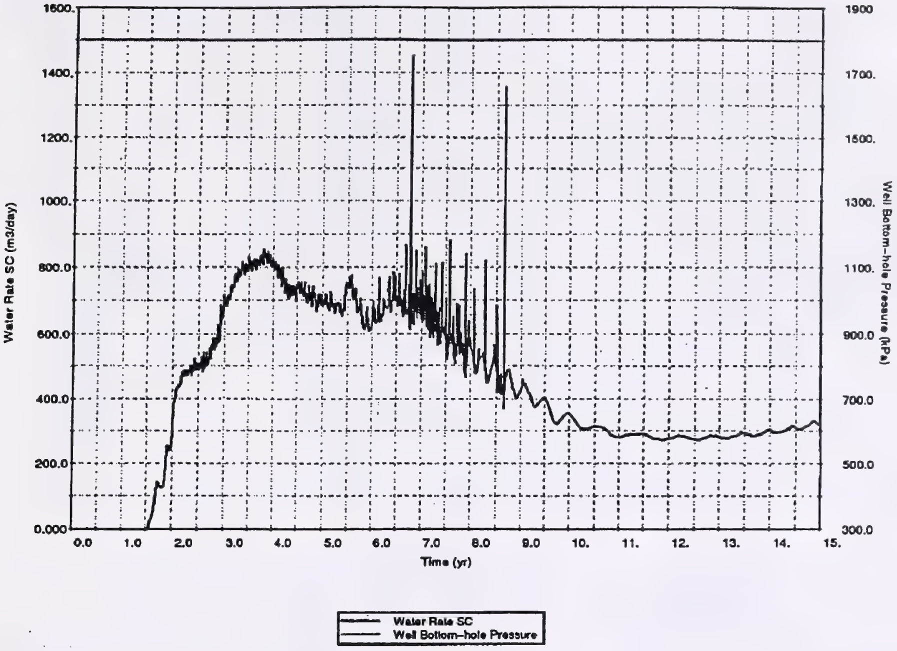
Athabasca McMurray — 10m Water Sands at 1800 kPa
Well Pair No. 1 Simulation Output



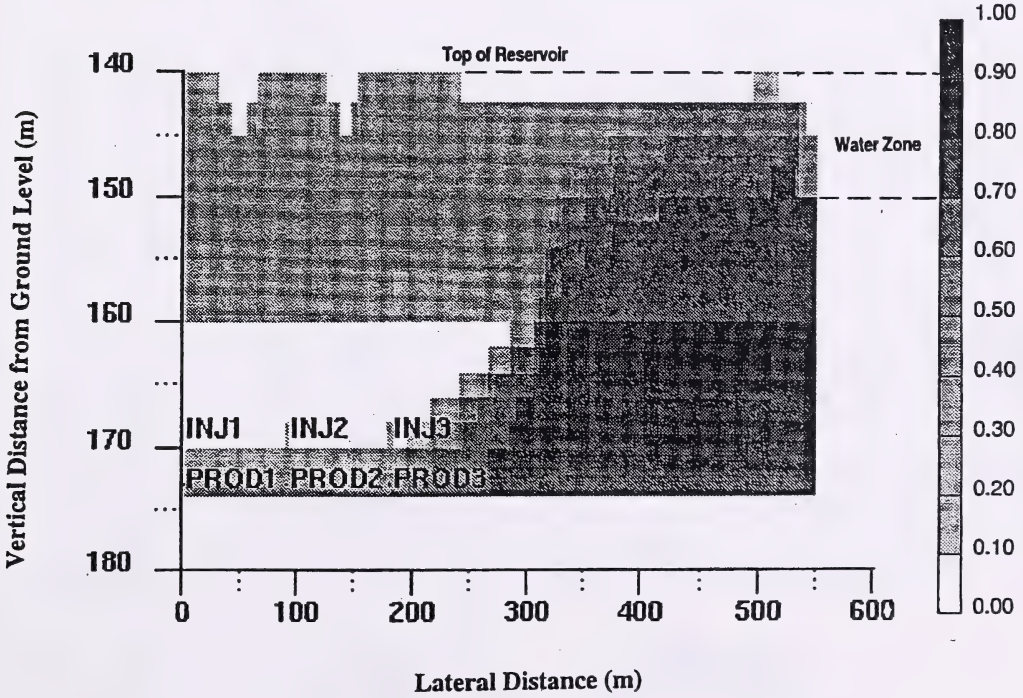
Athabasca McMurray — 10m Water Sands at 1800 kPa
Well Pair No. 2 Simulation Output



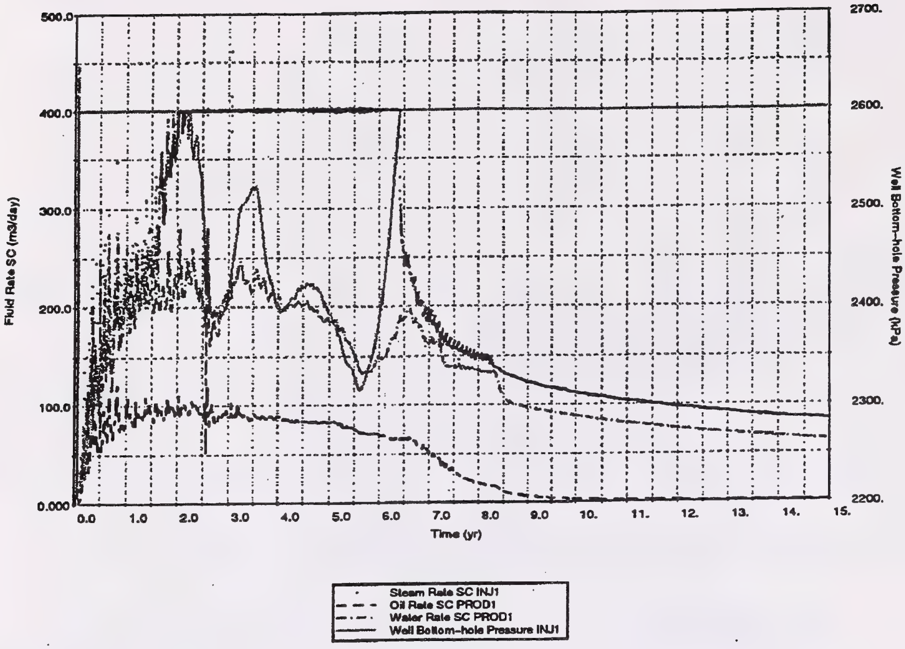
Athabasca McMurray — 10m Water Sands at 1800 kPa
Well Pair No. 3 Simulation Output



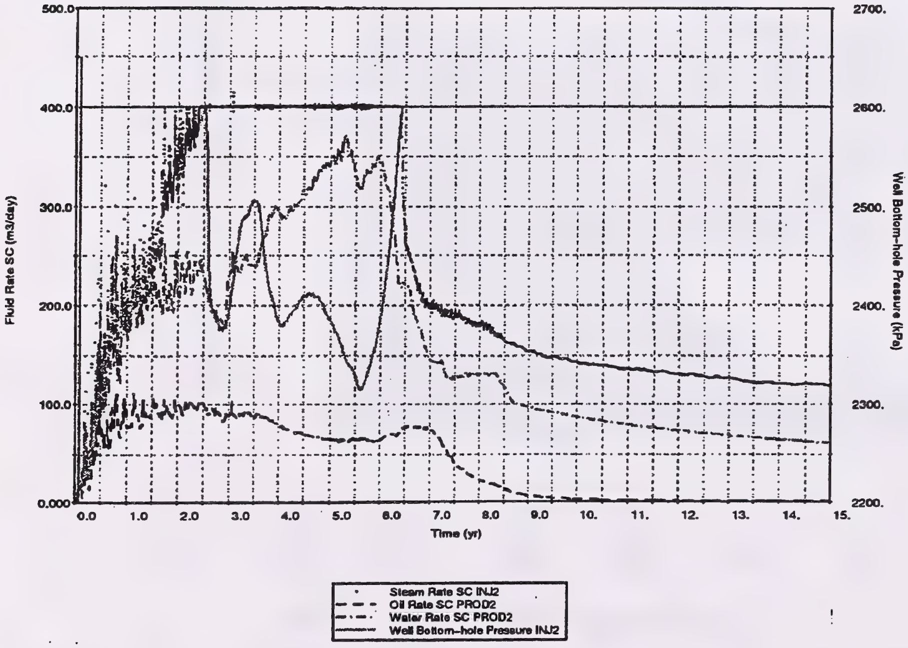
Athabasca McMurray — 10m Water Sands at 1800 kPa
Simulation Output from Pressure Sink Well



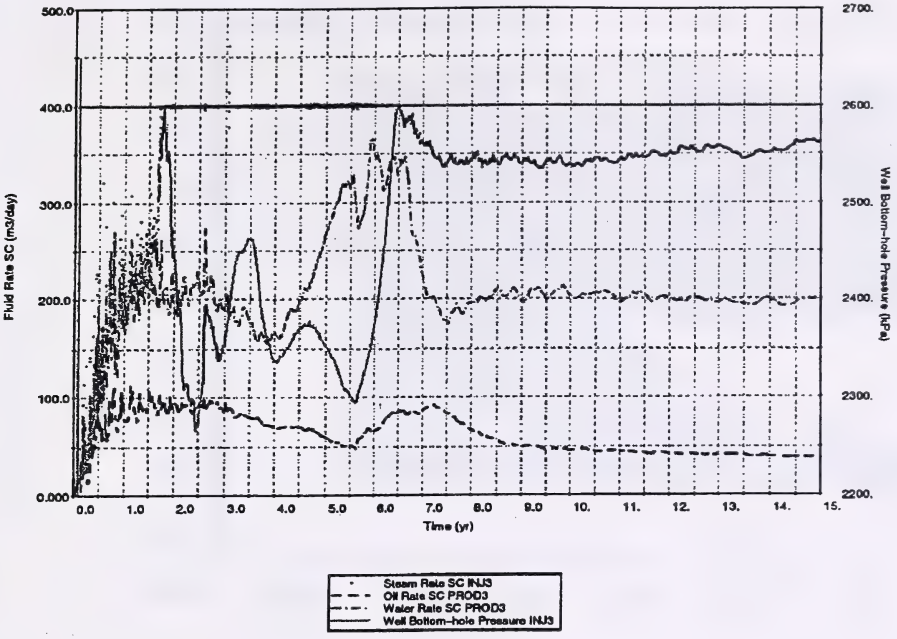
Athabasca McMurray — Reservoir Cross-Section — 10m Water Sands @ 1800 kPa
Bitumen Saturation @ End of Pattern Life



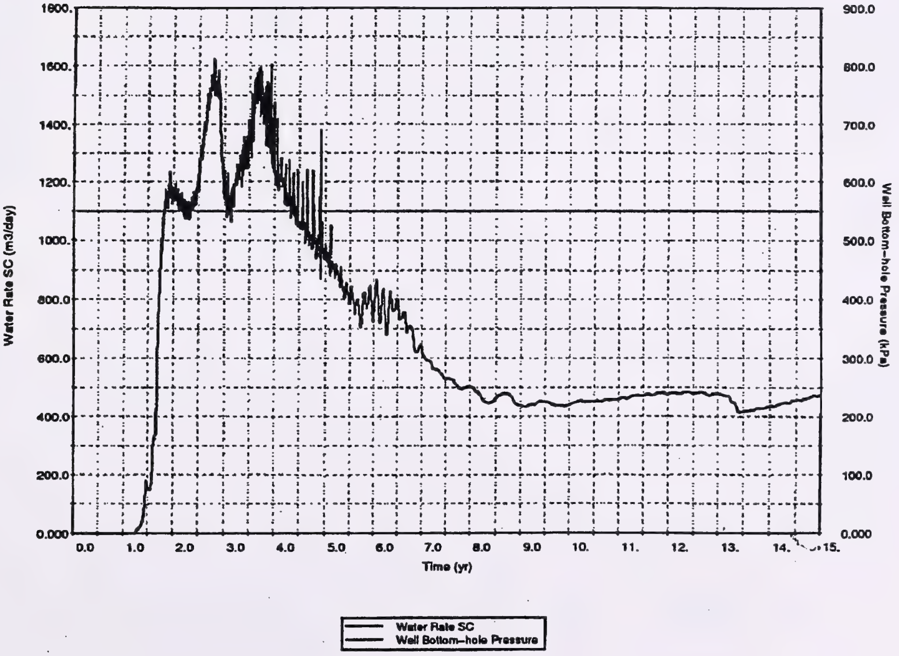
Athabasca McMurray — 10m Water Sands at 550 kPa
Well Pair No. 1 Simulation Output



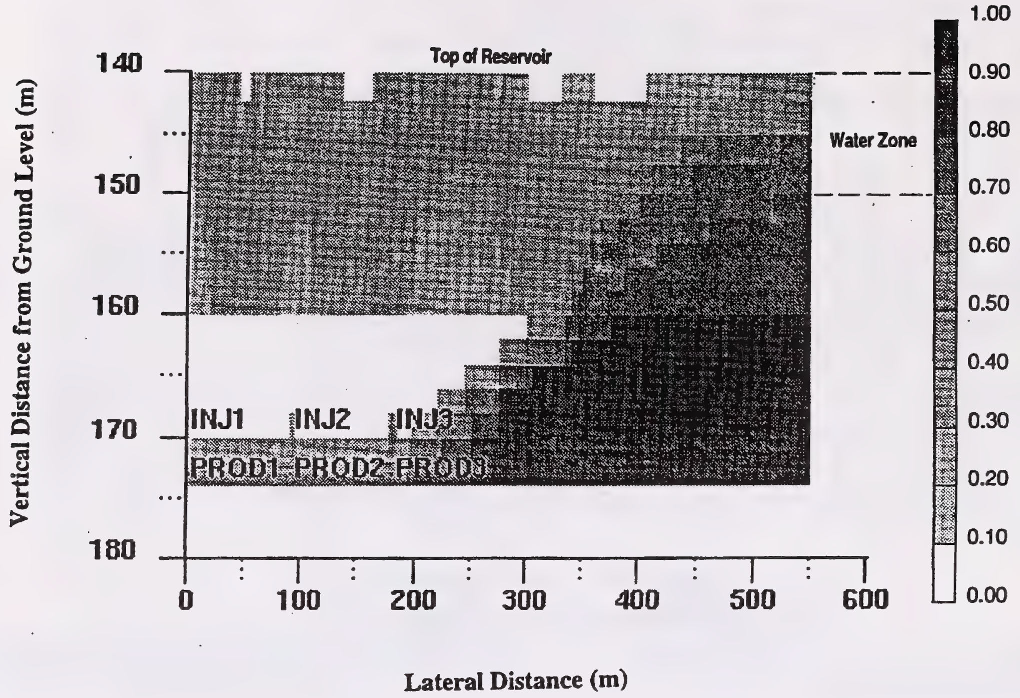
Athabasca McMurray — 10m Water Sands at 550 kPa
Well Pair No. 2 Simulation Output



Athabasca McMurray — 10m Water Sands at 550 kPa
Well Pair No. 3 Simulation Output



Athabasca McMurray — 10m Water Sands at 550 kPa
Simulation Output from Pressure Sink Well



Athabasca McMurray — Reservoir Cross-Section — 10m Water Sands @ 550 kPa
Bitumen Saturation @ End of Pattern Life

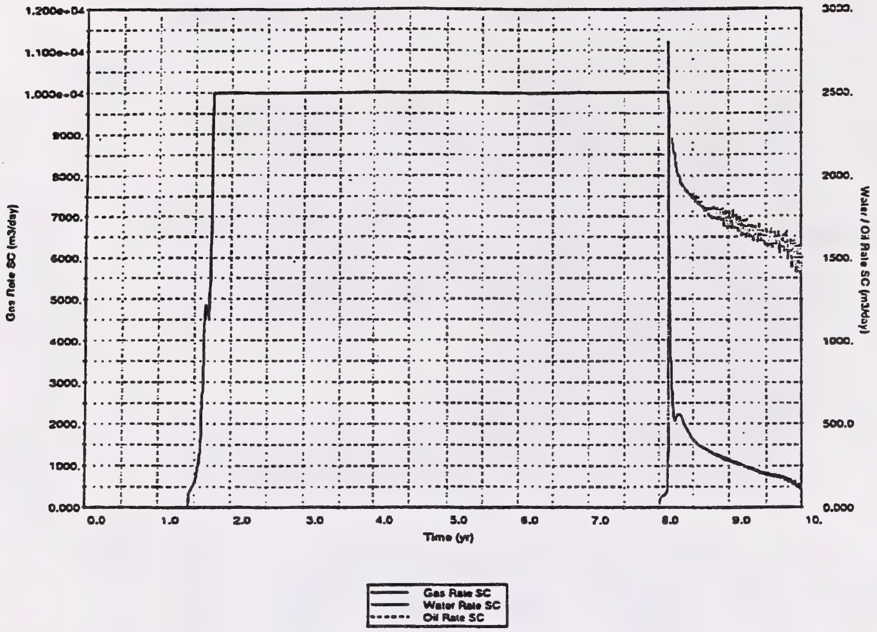
ATHABASCA McMURRAY — 10m GAS CAP at 1800 kPa

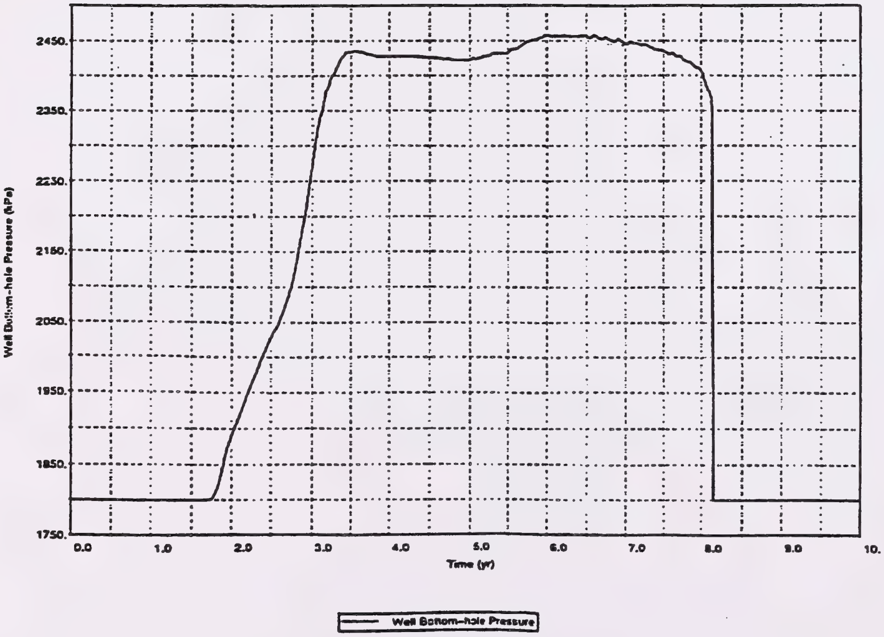
Simulation Output for:

Well Pair No. 1,
Well Pair No. 2,
and Well Pair No. 3

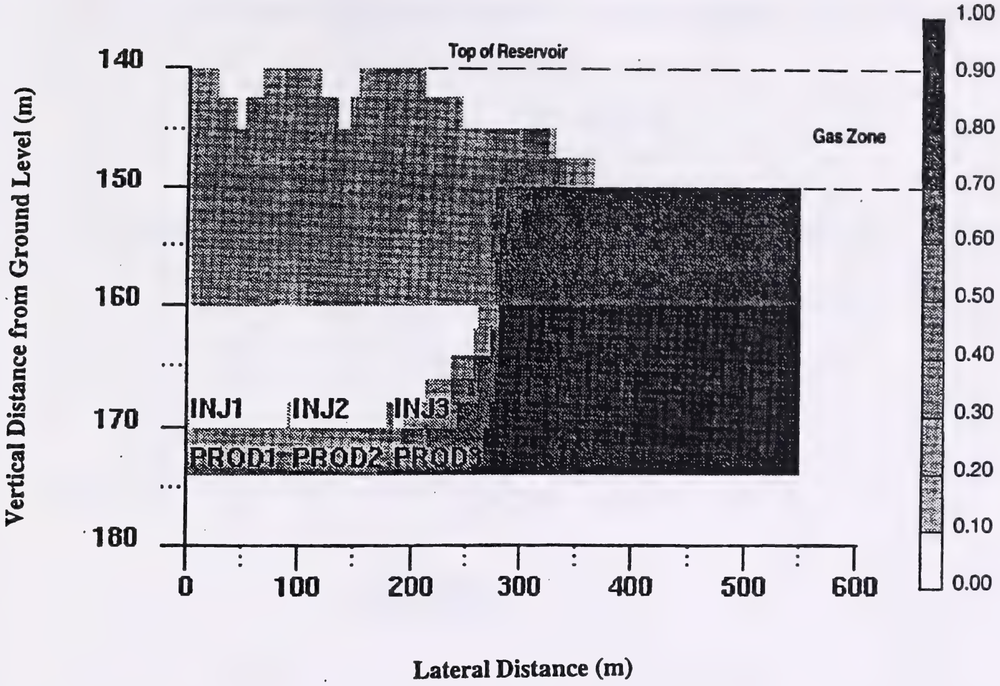
are shown in the report, "Possible Effects of Gas Caps on SAGD Performance"

March 1997.





Athabasca McMurray — 10m Non-depleted Gas Cap
Simulation Output of Gas Cap Well



Athabasca McMurray — Reservoir Cross-Section — 10m Gas Cap @ 1800 kPa
Bitumen Saturation @ End of Pattern Life

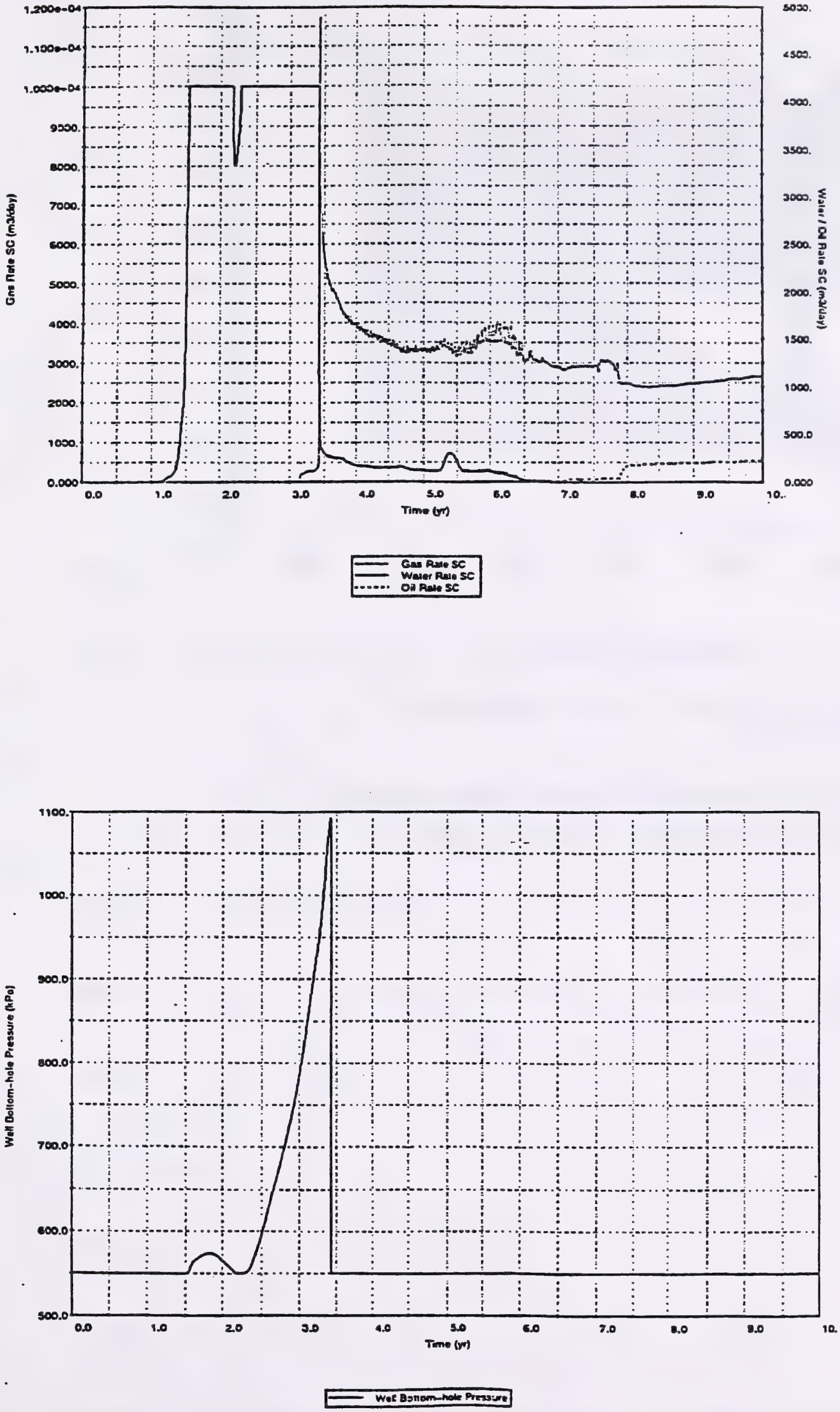
ATHABASCA McMURRAY — 10m GAS CAP at 550 kPa

Simulation Output for:

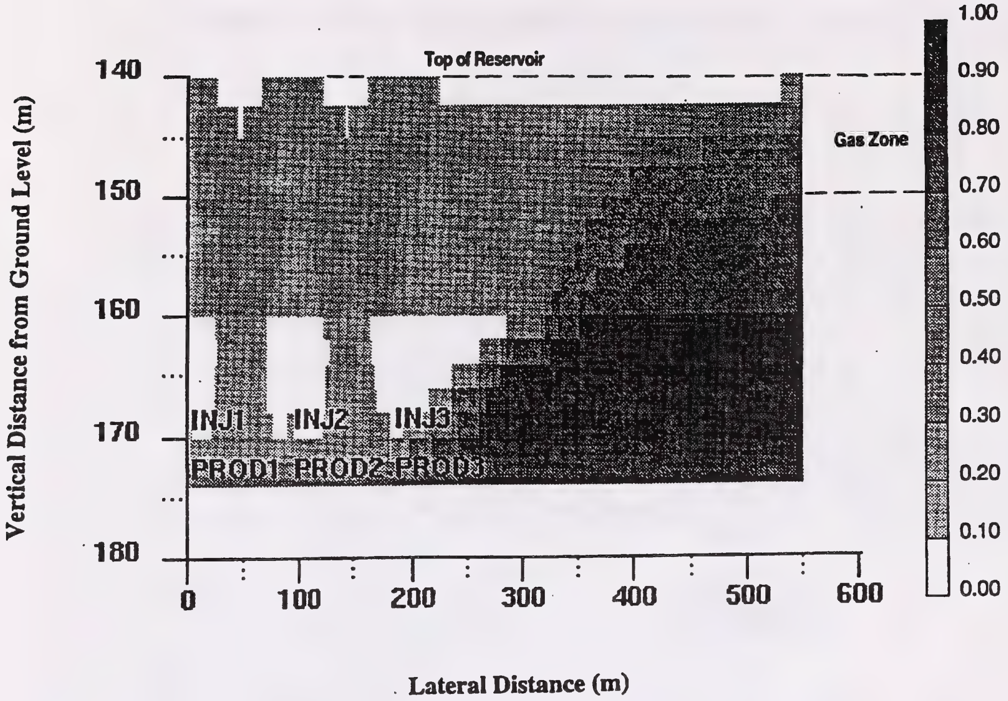
Well Pair No. 1,
Well Pair No. 2,
and Well Pair No. 3

are shown in the report, “Possible Effects of Gas Caps on SAGD Performance”

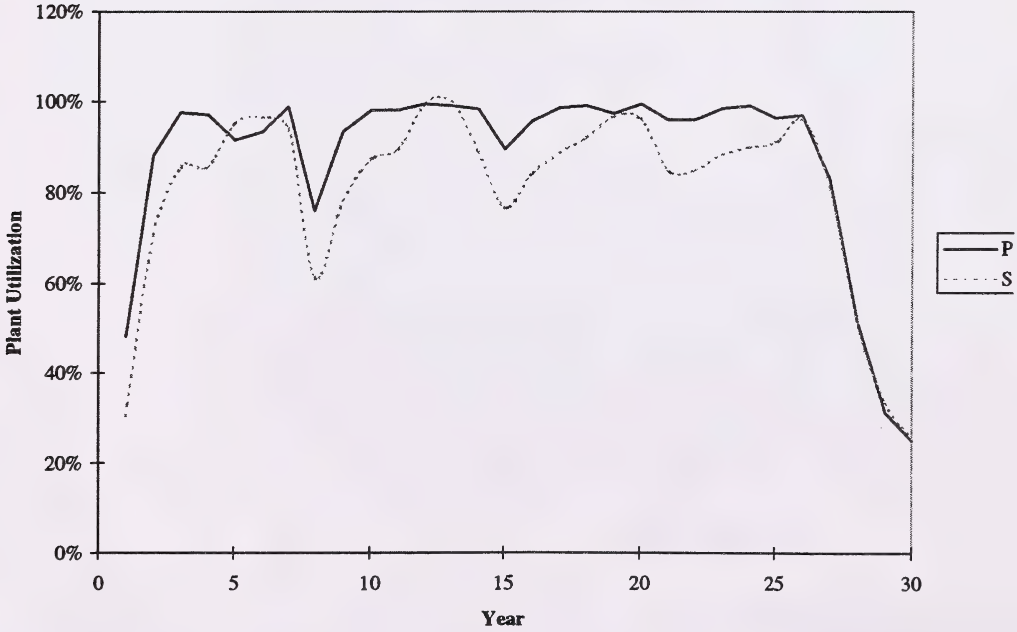
March 1997.



Athabasca McMurray — 10m Depleted Gas Cap
Simulation Output of Gas Cap Well

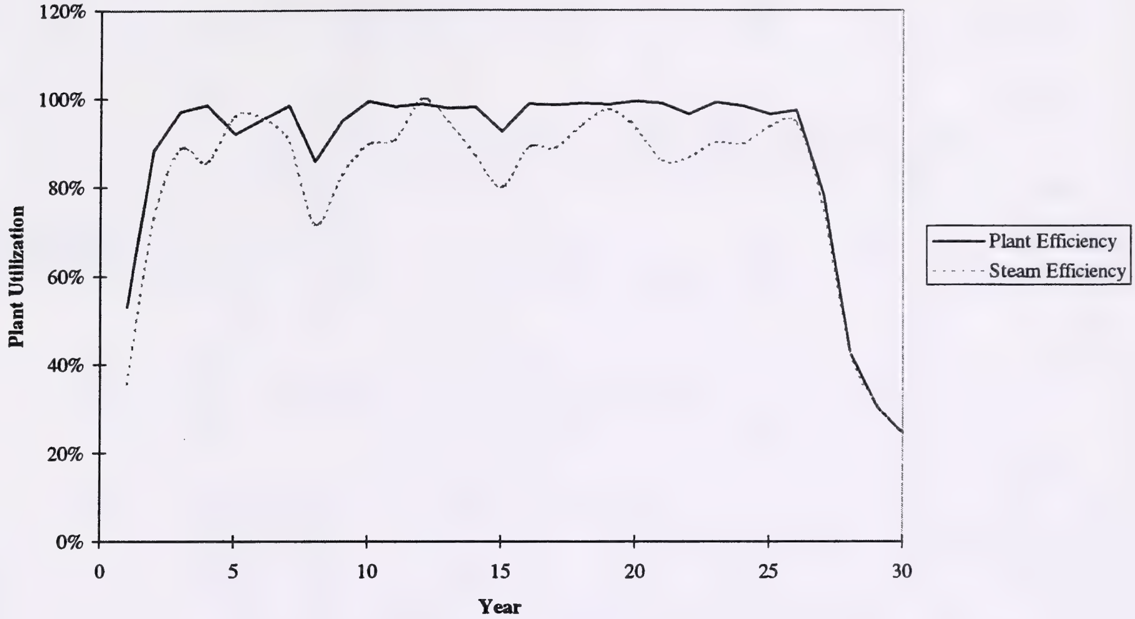


Athabasca McMurray — Reservoir Cross-Section — 10m Gas Cap @ 550 kPa
Bitumen Saturation @ End of Pattern Life

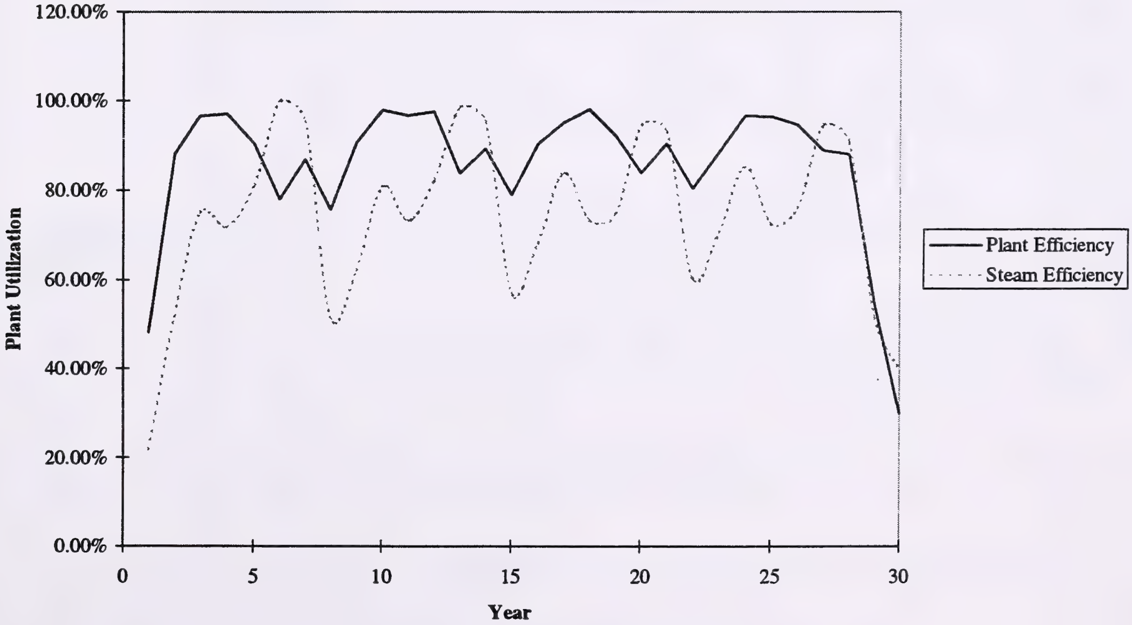

Plant Utilization of Bitumen and Steam Capacity

Athabasca McMurray - 5 m Water Sands at 1800 kPa

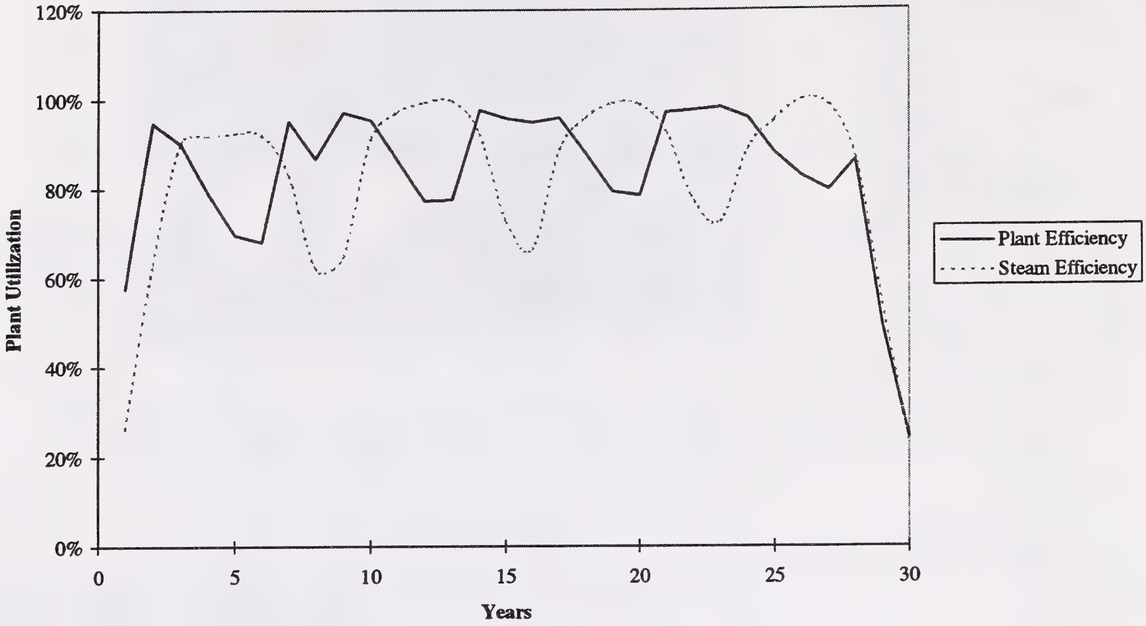
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 5 m Water Sands at 550 kPa



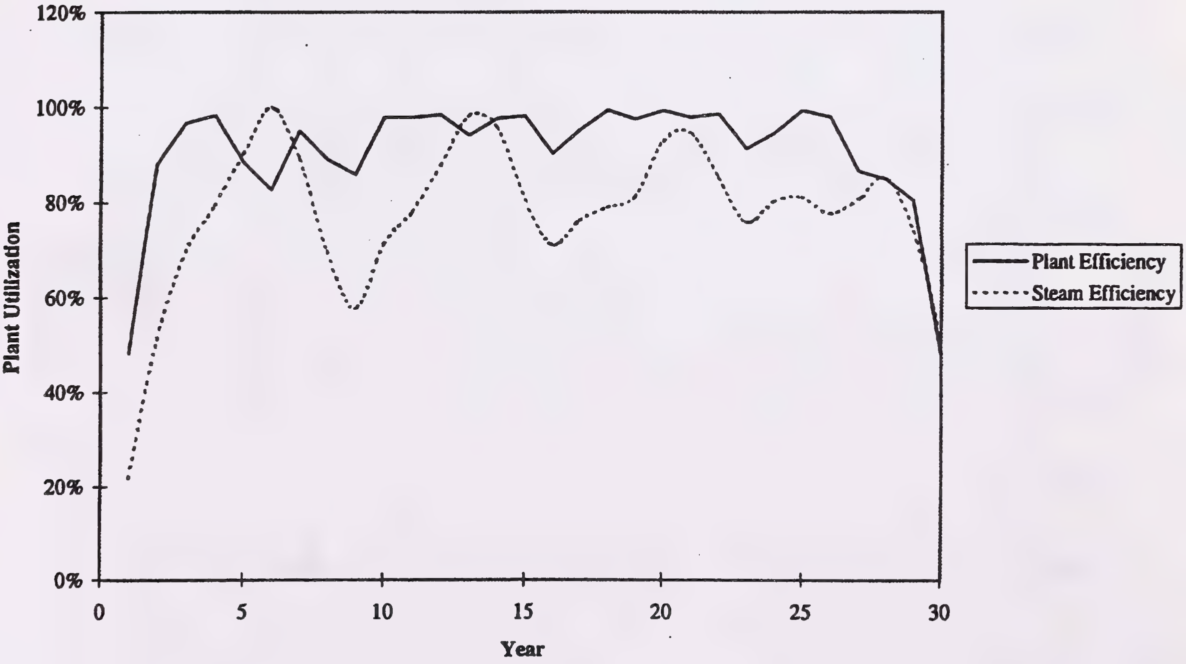
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 5 m Gas Cap & 5 m Water Sands at 1800 kPa



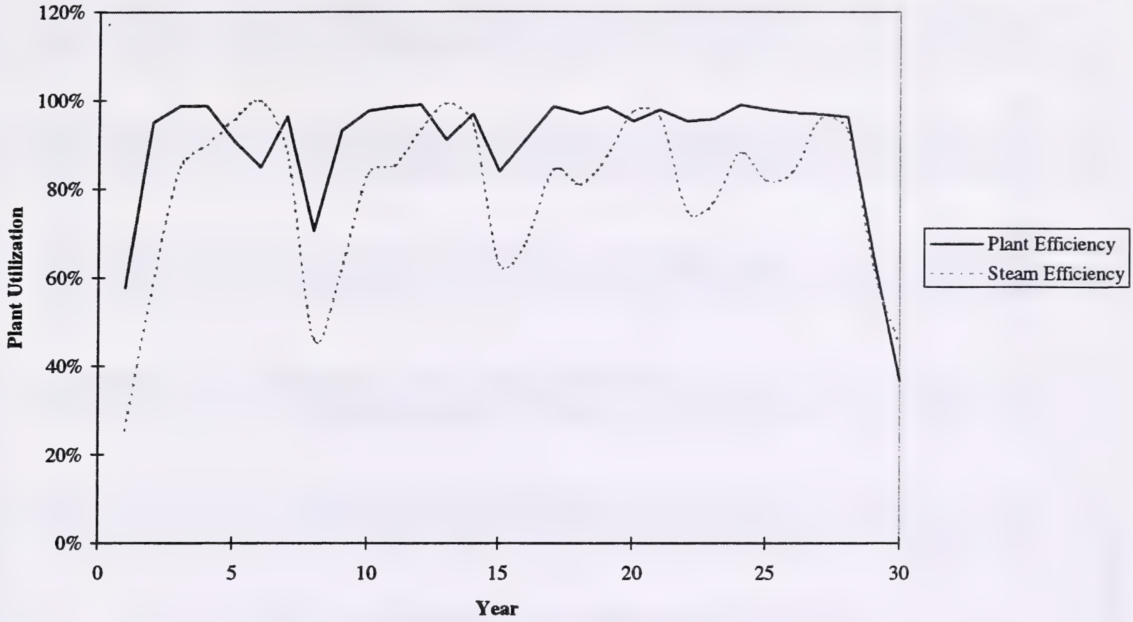
Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 5 m Gas Cap & 5 m Water Sands at 550 kPa



Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 10 m Water Sands at 1800 kPa



Plant Utilization of Bitumen and Steam Capacity
Athabasca McMurray - 10 m Water Sands at 550 kPa



Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 5 m Water Sands at 1800 kPa

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m³/d)	Steam Injection (m³/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$94	$235	$329						
1997	16			$21,600	$128	$319	$22,046						
1998	16			$21,600	$31,288	$78,072	$130,960						
1999	14			$18,900	$32,094	$80,082	$131,076						
2000	9	2,302	4,847	$12,150	$8,534	$21,293	$41,977	$9,916	$2,671	$746	$732	$10,850	$24,915
2001	9	4,202	11,260	$12,150			$12,150	$23,037	$6,206	$1,202	$1,663	$10,850	$42,957
2002	9	4,653	13,625	$12,150			$12,150	$27,875	$7,509	$1,310	$1,922	$10,850	$49,466
2003	9	4,630	13,650	$12,150			$12,150	$27,926	$7,523	$1,304	$1,974	$10,850	$49,578
2004	9	4,368	15,171	$12,150			$12,150	$31,040	$8,362	$1,241	$2,509	$10,850	$54,002
2005	9	4,445	15,390	$12,150			$12,150	$31,487	$8,482	$1,260	$2,555	$10,850	$54,634
2006	9	4,717	14,963	$12,150			$12,150	$30,612	$8,247	$1,325	$2,241	$10,850	$53,275
2007	9	3,623	9,752	$12,150			$12,150	$19,952	$5,375	$1,063	$1,449	$10,850	$38,689
2008	9	4,456	12,445	$12,150			$12,150	$25,462	$6,859	$1,263	$1,838	$10,850	$46,272
2009	9	4,679	13,896	$12,150			$12,150	$28,430	$7,659	$1,316	$1,987	$10,850	$50,242
2010	9	4,675	14,252	$12,150			$12,150	$29,158	$7,855	$1,315	$2,151	$10,850	$51,329
2011	9	4,742	15,835	$12,150			$12,150	$32,397	$8,727	$1,331	$2,578	$10,850	$55,884
2012	9	4,724	15,929	$12,150			$12,150	$32,591	$8,780	$1,327	$2,538	$10,850	$56,085
2013	9	4,689	14,150	$12,150			$12,150	$28,949	$7,799	$1,318	$2,133	$10,850	$51,049
2014	9	4,264	12,205	$12,150			$12,150	$24,970	$6,727	$1,217	$1,835	$10,850	$45,598
2015	9	4,564	13,393	$12,150			$12,150	$27,400	$7,381	$1,288	$1,994	$10,850	$48,914
2016	9	4,704	14,106	$12,150			$12,150	$28,859	$7,774	$1,322	$2,052	$10,850	$50,858
2017	9	4,723	14,649	$12,150			$12,150	$29,972	$8,074	$1,327	$2,268	$10,850	$52,491
2018	0	4,644	15,396	$0			$0	$31,499	$8,485	$1,307	$2,474	$10,850	$54,615
2019	0	4,746	15,319	$0			$0	$31,342	$8,443	$1,332	$2,369	$10,850	$54,336
2020	0	4,579	13,518	$0			$0	$27,657	$7,450	$1,292	$2,047	$10,850	$49,296
2021	0	4,581	13,528	$0			$0	$27,677	$7,456	$1,292	$2,057	$10,850	$49,333
2022	0	4,696	14,069	$0			$0	$28,784	$7,754	$1,320	$2,082	$10,850	$50,790
2023	0	4,723	14,318	$0			$0	$29,293	$7,891	$1,326	$2,120	$10,850	$51,480
2024	0	4,599	14,491	$0			$0	$29,648	$7,987	$1,297	$2,294	$10,850	$52,076
2025	0	4,623	15,294	$0			$0	$31,291	$8,429	$1,302	$2,418	$10,850	$54,291
2026	0	3,949	12,896	$0			$0	$26,385	$7,108	$1,141	$1,962	$10,850	$47,445
2027	0	2,445	8,162	$0			$0	$16,698	$4,498	$781	$1,261	$10,850	$34,088
2028	0	1,493	5,325	$0			$0	$10,894	$2,935	$553	$873	$10,850	$26,105
2029	0	1,191	4,052	$0			$0	$8,290	$2,233	$480	$639	$21,250	$32,893
Totals	208	45,781,317	140,847,259	$280,800	$72,138	$180,000	$532,938	$789,491	$212,679	$35,898	$59,015	$335,900	$1,432,984

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 5 m Water Sands at 550 kPa

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m^3/d)	Steam Injection (m^3/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$95	$235	$330						
1997	16			$21,600	$129	$319	$22,048						
1998	16			$21,600	$31,684	$78,072	$131,355						
1999	14			$18,900	$32,499	$80,082	$131,481						
2000	9	2,531	5,748	$12,150	$8,641	$21,293	$42,085	$11,761	$3,168	$801	$849	$10,850	$27,429
2001	9	4,213	11,776	$12,150			$12,150	$24,093	$6,490	$1,204	$1,683	$10,850	$44,320
2002	9	4,634	14,301	$12,150			$12,150	$29,260	$7,882	$1,305	$1,905	$10,850	$51,202
2003	9	4,704	13,821	$12,150			$12,150	$28,278	$7,618	$1,322	$2,085	$10,850	$50,152
2004	9	4,390	15,490	$12,150			$12,150	$31,692	$8,537	$1,247	$2,542	$10,850	$54,869
2005	9	4,552	15,428	$12,150			$12,150	$31,564	$8,503	$1,285	$2,482	$10,850	$54,684
2006	9	4,697	14,548	$12,150			$12,150	$29,765	$8,018	$1,320	$2,250	$10,850	$52,204
2007	9	4,094	11,559	$12,150			$12,150	$23,649	$6,371	$1,176	$1,677	$10,850	$43,722
2008	9	4,533	13,345	$12,150			$12,150	$27,303	$7,355	$1,281	$1,886	$10,850	$48,675
2009	9	4,746	14,464	$12,150			$12,150	$29,593	$7,972	$1,332	$2,033	$10,850	$51,780
2010	9	4,686	14,618	$12,150			$12,150	$29,907	$8,056	$1,318	$2,280	$10,850	$52,410
2011	9	4,717	16,131	$12,150			$12,150	$33,002	$8,890	$1,325	$2,599	$10,850	$56,666
2012	9	4,668	15,286	$12,150			$12,150	$31,274	$8,425	$1,313	$2,396	$10,850	$54,258
2013	9	4,677	14,035	$12,150			$12,150	$28,715	$7,736	$1,315	$2,123	$10,850	$50,739
2014	9	4,415	12,890	$12,150			$12,150	$26,371	$7,104	$1,253	$1,891	$10,850	$47,469
2015	9	4,711	14,346	$12,150			$12,150	$29,350	$7,907	$1,324	$2,040	$10,850	$51,470
2016	9	4,703	14,333	$12,150			$12,150	$29,324	$7,900	$1,322	$2,102	$10,850	$51,498
2017	9	4,720	15,169	$12,150			$12,150	$31,035	$8,360	$1,326	$2,394	$10,850	$53,965
2018	2	4,705	15,761	$2,700			$2,700	$32,247	$8,687	$1,322	$2,500	$10,850	$55,605
2019	0	4,743	15,022	$0			$0	$30,734	$8,279	$1,331	$2,299	$10,850	$53,493
2020	0	4,721	13,864	$0			$0	$28,364	$7,641	$1,326	$2,082	$10,850	$50,263
2021	0	4,604	13,970	$0			$0	$28,582	$7,700	$1,298	$2,046	$10,850	$50,475
2022	0	4,731	14,543	$0			$0	$29,754	$8,015	$1,328	$2,099	$10,850	$52,047
2023	0	4,688	14,498	$0			$0	$29,662	$7,991	$1,318	$2,203	$10,850	$52,023
2024	0	4,603	15,105	$0			$0	$30,903	$8,325	$1,298	$2,396	$10,850	$53,772
2025	0	4,644	15,226	$0			$0	$31,152	$8,392	$1,307	$2,363	$10,850	$54,065
2026	0	3,732	12,053	$0			$0	$24,661	$6,643	$1,089	$1,822	$10,850	$45,065
2027	0	2,035	6,912	$0			$0	$14,141	$3,810	$683	$1,074	$10,850	$30,558
2028	0	1,460	5,010	$0			$0	$10,250	$2,761	$545	$811	$10,850	$25,217
2029	0	1,169	3,944	$0			$0	$8,069	$2,174	$475	$623	$21,350	$32,691
Totals	210	46,072,240	143,516,787	$283,500	$73,049	$180,000	$536,549	$804,455	$216,710	$36,089	$59,534	$336,000	$1,452,788

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 5 m Gas Cap & 5 m Water Sands at 1800 kPa

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m^3/d)	Steam Injection (m^3/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$131	$235	$366						
1997	16			$21,600	$178	$319	$22,097						
1998	16			$21,600	$43,691	$78,072	$143,362						
1999	14			$18,900	$44,815	$80,082	$143,797						
2000	9	2,303	4,847	$12,150	$11,916	$21,293	$45,360	$9,917	$2,671	$747	$731	$10,850	$24,916
2001	9	4,197	11,509	$12,150			$12,150	$23,547	$6,343	$1,200	$1,656	$10,850	$43,596
2002	9	4,608	16,680	$12,150			$12,150	$34,126	$9,193	$1,299	$1,858	$10,850	$57,326
2003	9	4,627	15,967	$12,150			$12,150	$32,667	$8,800	$1,304	$1,988	$10,850	$55,608
2004	9	4,315	18,008	$12,150			$12,150	$36,843	$9,925	$1,229	$2,608	$10,850	$61,454
2005	9	3,727	22,244	$12,150			$12,150	$45,509	$12,260	$1,088	$3,075	$10,850	$72,782
2006	9	4,145	21,248	$12,150			$12,150	$43,472	$11,711	$1,188	$2,488	$10,850	$69,709
2007	9	3,611	11,500	$12,150			$12,150	$23,529	$6,338	$1,060	$1,424	$10,850	$43,202
2008	9	4,324	13,813	$12,150			$12,150	$28,260	$7,613	$1,231	$1,966	$10,850	$49,920
2009	9	4,674	18,004	$12,150			$12,150	$36,836	$9,923	$1,315	$2,065	$10,850	$60,989
2010	9	4,617	16,268	$12,150			$12,150	$33,284	$8,966	$1,301	$2,014	$10,850	$56,416
2011	9	4,655	18,282	$12,150			$12,150	$37,403	$10,076	$1,310	$2,604	$10,850	$62,244
2012	9	4,002	21,905	$12,150			$12,150	$44,816	$12,073	$1,154	$2,977	$10,850	$71,869
2013	9	4,259	21,210	$12,150			$12,150	$43,394	$11,690	$1,215	$2,500	$10,850	$69,649
2014	9	3,769	12,701	$12,150			$12,150	$25,985	$7,000	$1,098	$1,619	$10,850	$46,552
2015	9	4,315	15,156	$12,150			$12,150	$31,008	$8,353	$1,229	$2,159	$10,850	$53,599
2016	9	4,536	18,669	$12,150			$12,150	$38,196	$10,290	$1,282	$2,180	$10,850	$62,798
2017	9	4,675	16,308	$12,150			$12,150	$33,365	$8,988	$1,315	$1,956	$10,850	$56,473
2018	9	4,399	16,609	$12,150			$12,150	$33,980	$9,154	$1,249	$2,389	$10,850	$57,622
2019	5	3,999	21,020	$6,750			$6,750	$43,005	$11,585	$1,153	$2,817	$10,850	$69,410
2020	0	4,310	20,705	$0			$0	$42,361	$11,411	$1,228	$2,488	$10,850	$68,337
2021	0	3,838	13,429	$0			$0	$27,475	$7,401	$1,114	$1,710	$10,850	$48,550
2022	0	4,220	15,669	$0			$0	$32,057	$8,636	$1,206	$2,235	$10,850	$54,985
2023	0	4,605	18,969	$0			$0	$38,810	$10,455	$1,298	$2,219	$10,850	$63,632
2024	0	4,602	16,108	$0			$0	$32,956	$8,878	$1,298	$1,952	$10,850	$55,934
2025	0	4,516	16,880	$0			$0	$34,535	$9,303	$1,277	$2,406	$10,850	$58,371
2026	0	4,241	21,035	$0			$0	$43,037	$11,594	$1,211	$2,770	$10,850	$69,461
2027	0	4,197	20,168	$0			$0	$41,263	$11,116	$1,200	$2,448	$10,850	$66,877
2028	0	2,607	11,469	$0			$0	$23,464	$6,321	$819	$1,409	$10,850	$42,864
2029	0	1,430	8,813	$0			$0	$18,031	$4,857	$538	$1,241	$21,950	$46,617
Totals	222	44,647,544	180,744,846	$299,700	$100,732	$180,000	$580,432	$1,013,129	$272,925	$35,154	$63,954	$336,600	$1,721,762

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 5 m Gas Cap & 5 m Water Sands at 550 kPa

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m^3/d)	Steam Injection (m^3/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$140	$235	$375						
1997	17			$22,950	$190	$319	$23,459						
1998	17			$22,950	$46,630	$78,072	$147,652						
1999	16			$21,600	$47,831	$80,082	$149,512						
2000	9	2,750	6,250	$12,150	$12,718	$21,293	$46,161	$12,787	$3,445	$854	$923	$10,850	$28,858
2001	9	4,523	14,980	$12,150			$12,150	$30,648	$8,256	$1,279	$1,773	$10,850	$52,805
2002	9	4,302	21,473	$12,150			$12,150	$43,933	$11,835	$1,226	$1,582	$10,850	$69,425
2003	9	3,771	21,833	$12,150			$12,150	$44,669	$12,033	$1,098	$1,515	$10,850	$70,166
2004	9	3,326	21,952	$12,150			$12,150	$44,913	$12,099	$992	$1,987	$10,850	$70,841
2005	9	3,246	21,897	$12,150			$12,150	$44,800	$12,068	$973	$2,259	$10,850	$70,950
2006	9	4,540	19,709	$12,150			$12,150	$40,324	$10,863	$1,283	$1,887	$10,850	$65,205
2007	9	4,142	14,723	$12,150			$12,150	$30,122	$8,114	$1,187	$1,612	$10,850	$51,885
2008	9	4,636	15,348	$12,150			$12,150	$31,400	$8,459	$1,306	$1,793	$10,850	$53,807
2009	9	4,555	21,705	$12,150			$12,150	$44,407	$11,963	$1,286	$1,686	$10,850	$70,192
2010	9	4,125	23,112	$12,150			$12,150	$47,285	$12,738	$1,183	$1,677	$10,850	$73,733
2011	9	3,689	23,609	$12,150			$12,150	$48,302	$13,012	$1,079	$2,068	$10,850	$75,310
2012	9	3,697	23,693	$12,150			$12,150	$48,475	$13,059	$1,081	$2,355	$10,850	$75,819
2013	9	4,658	21,941	$12,150			$12,150	$44,890	$12,093	$1,311	$2,131	$10,850	$71,274
2014	9	4,570	17,249	$12,150			$12,150	$35,290	$9,507	$1,290	$1,819	$10,850	$58,756
2015	9	4,530	15,738	$12,150			$12,150	$32,199	$8,674	$1,280	$1,750	$10,850	$54,754
2016	9	4,580	21,103	$12,150			$12,150	$43,176	$11,631	$1,292	$1,731	$10,850	$68,680
2017	9	4,201	22,780	$12,150			$12,150	$46,606	$12,555	$1,201	$1,727	$10,850	$72,940
2018	9	3,787	23,558	$12,150			$12,150	$48,199	$12,984	$1,102	$2,026	$10,850	$75,161
2019	1	3,746	23,516	$1,350			$1,350	$48,111	$12,961	$1,092	$2,291	$10,850	$75,306
2020	0	4,636	22,016	$0			$0	$45,044	$12,134	$1,306	$2,154	$10,850	$71,489
2021	0	4,662	18,309	$0			$0	$37,459	$10,091	$1,312	$1,920	$10,850	$61,631
2022	0	4,690	17,232	$0			$0	$35,256	$9,497	$1,319	$1,839	$10,850	$58,761
2023	0	4,582	21,138	$0			$0	$43,247	$11,650	$1,293	$1,746	$10,850	$68,785
2024	0	4,208	22,641	$0			$0	$46,323	$12,479	$1,203	$1,772	$10,850	$72,627
2025	0	3,952	23,740	$0			$0	$48,571	$13,084	$1,142	$2,058	$10,850	$75,705
2026	0	3,797	23,435	$0			$0	$47,947	$12,916	$1,105	$2,244	$10,850	$75,062
2027	0	4,126	20,709	$0			$0	$42,370	$11,414	$1,184	$1,959	$10,850	$67,776
2028	0	2,345	12,819	$0			$0	$26,227	$7,065	$757	$1,166	$10,850	$46,064
2029	0	1,159	5,435	$0			$0	$11,119	$2,995	$473	$496	$21,950	$37,034
Totals	222	43,629,366	213,029,974	$299,700	$107,510	$180,000	$587,210	$1,194,097	$321,675	$34,486	$53,944	$336,600	$1,940,802

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 10 m Water Sands at 1800 kPa

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m³/d)	Steam Injection (m³/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$131	$235	$366						
1997	16			$21,600	$178	$319	$22,097						
1998	16			$21,600	$43,584	$78,072	$143,256						
1999	14			$18,900	$44,706	$80,082	$143,688						
2000	9	2,297	4,832	$12,150	$11,887	$21,293	$45,330	$9,887	$2,663	$745	$730	$10,850	$24,875
2001	9	4,196	11,319	$12,150			$12,150	$23,157	$6,238	$1,200	$1,661	$10,850	$43,106
2002	9	4,612	15,441	$12,150			$12,150	$31,590	$8,510	$1,300	$1,894	$10,850	$54,144
2003	9	4,690	17,643	$12,150			$12,150	$36,097	$9,724	$1,319	$1,986	$10,850	$59,976
2004	9	4,215	20,063	$12,150			$12,150	$41,047	$11,058	$1,205	$2,558	$10,850	$66,718
2005	9	3,942	22,189	$12,150			$12,150	$45,398	$12,230	$1,139	$2,973	$10,850	$72,590
2006	9	4,536	19,760	$12,150			$12,150	$40,428	$10,891	$1,282	$2,649	$10,850	$66,099
2007	9	4,248	15,458	$12,150			$12,150	$31,626	$8,520	$1,213	$1,841	$10,850	$54,049
2008	9	4,095	12,778	$12,150			$12,150	$26,143	$7,043	$1,176	$1,808	$10,850	$47,020
2009	9	4,669	15,814	$12,150			$12,150	$32,355	$8,716	$1,314	$2,033	$10,850	$55,268
2010	9	4,669	17,347	$12,150			$12,150	$35,491	$9,561	$1,314	$2,039	$10,850	$59,254
2011	9	4,694	19,504	$12,150			$12,150	$39,903	$10,749	$1,320	$2,459	$10,850	$65,281
2012	9	4,492	21,827	$12,150			$12,150	$44,656	$12,030	$1,271	$2,877	$10,850	$71,684
2013	9	4,661	21,234	$12,150			$12,150	$43,444	$11,703	$1,312	$2,800	$10,850	$70,109
2014	9	4,684	17,880	$12,150			$12,150	$36,580	$9,854	$1,317	$2,182	$10,850	$60,783
2015	9	4,305	15,762	$12,150			$12,150	$32,248	$8,687	$1,226	$2,112	$10,850	$55,124
2016	9	4,547	16,911	$12,150			$12,150	$34,599	$9,321	$1,284	$2,245	$10,850	$58,298
2017	9	4,744	17,528	$12,150			$12,150	$35,861	$9,660	$1,332	$2,102	$10,850	$59,805
2018	9	4,651	18,044	$12,150			$12,150	$36,917	$9,945	$1,309	$2,261	$10,850	$61,282
2019	5	4,739	20,630	$6,750			$6,750	$42,207	$11,370	$1,330	$2,720	$10,850	$68,478
2020	0	4,669	20,998	$0			$0	$42,961	$11,573	$1,313	$2,744	$10,850	$69,441
2021	0	4,703	18,873	$0			$0	$38,613	$10,402	$1,322	$2,288	$10,850	$63,475
2022	0	4,353	16,838	$0			$0	$34,450	$9,280	$1,238	$2,205	$10,850	$58,023
2023	0	4,510	17,788	$0			$0	$36,393	$9,804	$1,275	$2,428	$10,850	$60,750
2024	0	4,737	17,986	$0			$0	$36,799	$9,913	$1,330	$2,215	$10,850	$61,107
2025	0	4,674	17,250	$0			$0	$35,293	$9,507	$1,315	$2,091	$10,850	$59,055
2026	0	4,130	17,896	$0			$0	$36,614	$9,863	$1,184	$2,354	$10,850	$60,865
2027	0	4,050	18,896	$0			$0	$38,660	$10,415	$1,165	$2,461	$10,850	$63,551
2028	0	3,837	16,421	$0			$0	$33,597	$9,051	$1,114	$2,007	$10,850	$56,618
2029	0	2,291	11,511	$0			$0	$23,551	$6,344	$744	$1,408	$21,950	$53,997
Totals	222	47,318,486	188,493,719	$299,700	$100,486	$180,000	$580,186	$1,056,564	$284,626	$36,907	$66,129	$336,600	$1,780,825

Commercial Plant Forecast and Undiscounted Costs (1995 Dollars)

Athabasca McMurray - 10 m Water Sands at 550 kPa

				Capital Cost (Thousand $)				Operating Cost (Thousand $)					
Year	Well Pairs Drilled	Bitumen Prod. (m^3/d)	Steam Injection (m^3/d)	Drilling	Steam Facilities	Other Facilities	Total Capital	Gas Cost	Utilities	Production Treating	Water Treating	Fixed and Other	Total Operating Cost
1995	0												
1996	0				$146	$235	$380						
1997	17			$22,950	$198	$319	$23,466						
1998	17			$22,950	$48,444	$78,072	$149,466						
1999	16			$21,600	$49,691	$80,082	$151,373						
2000	9	2,757	6,269	$12,150	$13,213	$21,293	$46,656	$12,826	$3,455	$855	$923	$10,850	$28,909
2001	9	4,536	14,348	$12,150			$12,150	$29,356	$7,908	$1,282	$1,787	$10,850	$51,183
2002	9	4,717	20,895	$12,150			$12,150	$42,750	$11,516	$1,325	$1,827	$10,850	$68,268
2003	9	4,713	22,207	$12,150			$12,150	$45,433	$12,239	$1,324	$2,037	$10,850	$71,883
2004	9	4,341	23,612	$12,150			$12,150	$48,309	$13,014	$1,235	$2,409	$10,850	$75,817
2005	9	4,050	24,664	$12,150			$12,150	$50,460	$13,593	$1,165	$2,845	$10,850	$78,914
2006	9	4,604	21,830	$12,150			$12,150	$44,662	$12,031	$1,298	$2,546	$10,850	$71,387
2007	9	3,369	11,413	$12,150			$12,150	$23,349	$6,290	$1,002	$1,359	$10,850	$42,851
2008	9	4,445	15,119	$12,150			$12,150	$30,932	$8,333	$1,260	$1,925	$10,850	$53,300
2009	9	4,658	20,555	$12,150			$12,150	$42,054	$11,329	$1,311	$1,948	$10,850	$67,492
2010	9	4,702	21,028	$12,150			$12,150	$43,021	$11,589	$1,321	$1,978	$10,850	$68,761
2011	9	4,726	23,063	$12,150			$12,150	$47,184	$12,711	$1,327	$2,374	$10,850	$74,447
2012	9	4,347	24,508	$12,150			$12,150	$50,142	$13,508	$1,236	$2,713	$10,850	$78,449
2013	9	4,624	23,345	$12,150			$12,150	$47,763	$12,867	$1,303	$2,600	$10,850	$75,382
2014	9	4,006	15,575	$12,150			$12,150	$31,866	$8,584	$1,155	$1,771	$10,850	$54,225
2015	9	4,350	16,764	$12,150			$12,150	$34,298	$9,239	$1,237	$2,069	$10,850	$57,694
2016	9	4,705	20,816	$12,150			$12,150	$42,588	$11,473	$1,322	$2,108	$10,850	$68,341
2017	9	4,630	19,980	$12,150			$12,150	$40,877	$11,012	$1,304	$1,952	$10,850	$65,996
2018	9	4,702	21,547	$12,150			$12,150	$44,083	$11,875	$1,321	$2,247	$10,850	$70,377
2019	9	4,549	24,072	$12,150			$12,150	$49,250	$13,267	$1,285	$2,625	$10,850	$77,278
2020	9	4,672	23,704	$12,150			$12,150	$48,497	$13,065	$1,314	$2,529	$10,850	$76,255
2021	1	4,551	18,495	$1,350			$1,350	$37,840	$10,194	$1,285	$2,089	$10,850	$62,258
2022	0	4,571	18,991	$0			$0	$38,853	$10,467	$1,290	$2,259	$10,850	$63,719
2023	0	4,724	21,748	$0			$0	$44,496	$11,987	$1,327	$2,240	$10,850	$70,899
2024	0	4,682	20,218	$0			$0	$41,365	$11,143	$1,317	$2,025	$10,850	$66,700
2025	0	4,644	20,704	$0			$0	$42,358	$11,411	$1,308	$2,222	$10,850	$68,149
2026	0	4,624	23,711	$0			$0	$48,511	$13,068	$1,303	$2,583	$10,850	$76,315
2027	0	4,598	22,971	$0			$0	$46,998	$12,661	$1,297	$2,414	$10,850	$74,219
2028	0	3,068	15,271	$0			$0	$31,243	$8,416	$930	$1,566	$10,850	$53,005
2029	0	1,752	10,943	$0			$0	$22,389	$6,031	$615	$1,222	$22,850	$53,107
Totals	240	47,238,070	214,752,659	$324,000	$111,692	$180,000	$615,692	$1,203,753	$324,277	$36,854	$63,194	$337,500	$1,965,578

Appendix 4

Alberta Oil Sands Technology and Research Authority

Extending the SAGD Process to Other Reservoir Types — Sensitivity Study

by

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Engineering and Technology Development
Calgary, Alberta, Canda — October 1992

Executive Summary

A good quality oil sands formation, typical of the Athabasca oil sands, was chosen as the base case for this SAGD sensitivity study. The relative effects of major parameters were investigated by varying its value individually. These included: inter-well spacing, formation thickness, permeabilities, water saturation, connate water saturation, formation wettabilities and oil viscosities. Some heterogeneities, such as, tight streak, bottom water layer and layered formations were also incorporated into the study.

It was found that the process predictability was quite dependable on formation absolute permeabilities. For the base case, where higher permeabilities were used, increased inter-well spacing between producer and injector did not effect the process much, although the start-up was delayed as anticipated. The oil rate was also in proportion to its formation thickness. However, for a lower permeability case, larger inter-well spacing showed a much better oil rate than that of the smaller inter-well spacing, while the increased formation thickness hardly affected the oil rates. Realizing the different performances of high and low permeability formations, more emphasis was given to low quality reservoirs in these studies. It was found that a SAGD process in a low permeability formation could be enhanced by injecting at a higher location and at a higher pressure. Performance was even better, if the formation was strongly oil-wet.

Preliminary investigations on wettability indicated that oil-wet formations are more favorable candidates for SAGD processes. This is different from most conventional driving processes, such as a water flood, etc.

The presence of a non permeable tight streak did not affect the process much, neither did a bottom water layer. With layered formations, the well performance depends on the permeability of the different layers and the location of the wells. A better performance is observed when the higher permeability is below the lower permeability layer and both wells are located in the higher permeability layer. Effects of oil viscosities were not found to be significant. Both lighter heavy oil and more viscous oil sands tended to have similar behavior at steam temperatures.

Acknowledgments

We wish to acknowledge the encouragement and support of the management of the Alberta Oil Sands Technology and Research Authority (AOSTRA) throughout the course of this work.

It has been a great learning experience, and we are still learning. Many interesting discussions with many people laid foundations for the study. We would like to express our appreciation and gratitude to: Simon Gittins, Neil Edmunds, and Neha Mukherjee as well as many other colleagues at AOSTRA.

Table of Contents

Objectives
Introduction
Results and Discussion
1). Sensitivity of grid sizes
2). Effects of formation thickness
3). Effects of injector/producer inter-well spacing
4). Effects of absolute permeabilities
    a) Effects of vertical permeability
    b) Effects of horizontal permeability
    c) Effects of horizontal and vertical permeabilities
5). Effects of lower oil saturation (higher water saturation)
6). Effects of wettability
7). Effects of tight streaks
    a) one tight streak
    b) two tight streaks
8). Effects of a bottom water layer
9). Effects of a layered formation
10). Effects of oil viscosities
11). Correlations among peak oil rate, breakthrough, and formation top
12). Low permeability SAGD enhancement
Major Conclusions
References

List of Figures

Figure 1.1 Grid Block Size Sensitivity – Effects on Oil Rates
Figure 1.2 Grid Block Size Sensitivity – Effects on Steam Rates
Figure 1.3 Grid Block Size Sensitivity – Effects on Water Rates
Figure 1.4 Grid Block Size Sensitivity – Cum. Oil
Figure 1.5 Grid Block Size Sensitivity – Cum. Steam
Figure 1.6 Grid Block Size Sensitivity – Cum. Water
Figure 2.1 Effects of Formation Thickness – Oil Rate
Figure 2.2 Effects of Formation Thickness – Low Permeability
Figure 2.3 Base Case Steam Chambers
Figure 2.4 Thick Formation Steam Chambers
Figure 2.5 Thick Formation – Low Permeability
Figure 3.1 Effects of Inter-Well Spacing – high permeability
Figure 3.2 Effects of Inter-Well Spacing – low permeability
Figure 3.3 Low Permeability – Larger Spacing
Figure 4.1 Effects of Vertical Permeability – Oil Rate
Figure 4.2 Effects of Horizontal Permeability – Oil Rate
Figure 4.3 Effects of Horizontal and Vertical Permeabilities
Figure 4.4 Effects of Kv on Steam Chambers
Figure 4.5 Effects of Kh on Steam Chambers
Figure 5.1 Effects of Water Saturations on Oil Rates
Figure 5.2 Effects of Water Saturations on Water Rates
Figure 5.3 Effects of Water Saturations on Steam Rates
Figure 6.1 Relative Permeability Curves – Liquid-Gas
Figure 6.2 Relative Permeability Curves – Water-Oil
Figure 6.3 Effects of Wettability on Oil Rates
Figure 6.4 Effects of Wettability on Water Rates
Figure 6.5 Effects of Wettability on Steam Rates
Figure 6.6 Oil-wet Case – Water Saturations
Figure 6.7 Base Case – Water Saturations
Figure 6.8 Water-wet Case – Water Saturations
Figure 7.1 Effects of a Tight Streak on Oil Rates
Figure 7.2 Effects of Two Tight Streaks on Oil Rates
Figure 7.3 Effects of Tight Streaks on Steam Rates
Figure 7.4 One Tight Streak Case – Steam Chambers
Figure 7.5 Two Tight Streak Case – Steam Chambers
Figure 8.1 Effects of a Bottom Water Layer
Figure 8.2 A Bottom Water Case – Oil Saturations
Figure 9.1 Two Layer Formation – Oil Rates
Figure 9.2 Two Layer Formation – Compared to UTF Type
Figure 9.3 A Layered Formation – High K at Upper Layer
Figure 9.4 A Layered Formation – High K at Lower Layer
Figure 9.5 A Layered Formation – High K at Middle Layer
Figure 10.1 Effects of Viscosities
Figure 12.1 Low Permeability SAGD Enhancement
Figure 12.2 Low K, Larger Spacing and Higher P

Objectives

The main objective of this study was to evaluate the sensitivity of the SAGD process to changes in major reservoir parameters using typical Athabasca reservoir as a base case. This will allow better understanding of how other reservoir types might perform relative to the UTF reservoir.

Introduction

The UTF Phase A has successfully demonstrated the effectiveness of the SAGD process for bitumen recovery. Current predictions for the longer well Phase B operations include an expected recovery of more than 65%, with a cumulative daily oil rate of over 100 cubic meters per well pair. These results have inspired growing interest from oil industries throughout the world. Along with this, there are many questions regarding the process feasibility in other reservoir types.

In order to answer these questions, especially those from potential users of the process, a sensitivity study was undertaken to cover a wide range of the reservoir parameters. However, the study neglected two very important factors: optimization and economics. It focused only on sensitivities. The Phase 1 study included reservoir types ranging from as good as the 40 meter thick Athabasca prime pay to some low-quality reservoirs, such formations with low permeability and high water saturation. The effects of bottom water and heterogeneity were also investigated.

The study started with typical UTF reservoir parameters then went on to explore other possibilities. The base case used the following major parameters:

	Base Case
Horizontal Permeability:	10 Darcy
Vertical Permeability:	5 Darcy
Porosity:	35%
Oil Saturation:	85%
Formation thickness:	20 m
Inter-well spacing:	5 m
Spacing between well pairs:	70 m
Operation pressure:	2700 kPa

The base case reservoir was considered to be high permeability, while low permeability cases used a horizontal permeability of 1 Darcy and a vertical permeability of 0.5 Darcy. High-pressure studies employed 7000 kPa as the injection pressure. All studies used UTF steam trap control as a standard production well control technique.

The simulator used was CMG's STARS, and all graphs were generated using AGS (AOSTRA Graphics System). A two-dimensional cross section through the well pair was chosen at this stage with a few major assumptions: the well pair was in the middle of a bank of horizontal well pairs; the reservoirs were homogeneous along the entire length of the horizontal section. Most of the numbers reported were converted from a "per meter injection or production well" to a "per 500 meter well pair" basis to facilitate direct comparisons with the UTF Phase B well pairs.

Results and Discussion

1) Sensitivities of Grid Sizes

Experiences on simulation of gravity drainage problems have indicated that very small grid block sizes are required. Figure 1.1 to Figure 1.6 showed that using two metres by two metres grid block sizes underestimated oil and water production, as well as steam injection. It also created too much fluctuations on all reported rates. The smallest grid block size possible at this stage was 1/2 metre by 1/2 metre and it did produce the best results available. But in order to use this fine grid, one had to limit the maximum formation thickness to 20 metres, and the maximum spacing between well pairs to 60 metres. This was not enough for our study purpose, where a thickness of 40 metres and a spacing of 70 metres had to be accommodated. Using one metre by one metre grid block size slightly underestimated the rates, but its cumulative 2-year was very close to those of the 1/2 metre by 1/2 metre case.

It was decided that one metre by one metre grid block size be used as a standard to complete our study, but the results should be interpreted with caution. For example, it was noticed from Figure 1.1, the peak oil rates of the one metre by one metre case lasted much longer than those of the 1/2 metre by 1/2 metre case. This should be corrected, although the magnitude of the peak rate could be expected to be reasonable. Further discussions on peak rate will be seen in Section 11. The fluctuations of rates, especially the steam injection rates were purely reflections of grid block sizes. As the grid block size went smaller, the fluctuations decreased. And eventually, they should disappear when the grid block size used was small enough.

It should be realized that this report was intended to emphasize the trend in relative terms. Most of the reported rates should be treated as rough estimates rather than true representations.

Oil Production Rate Comparisons

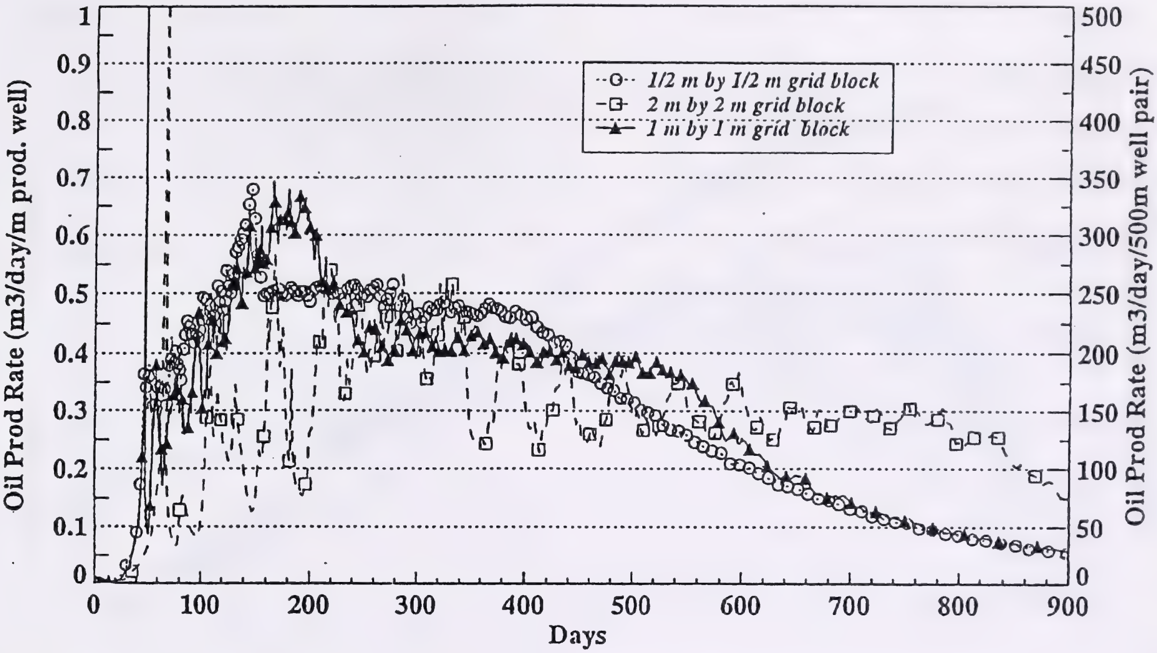


Figure 1.1 — Grid Block Size Sensitivity — Effects on Oil Rates

Steam Injection Rate Comparisons

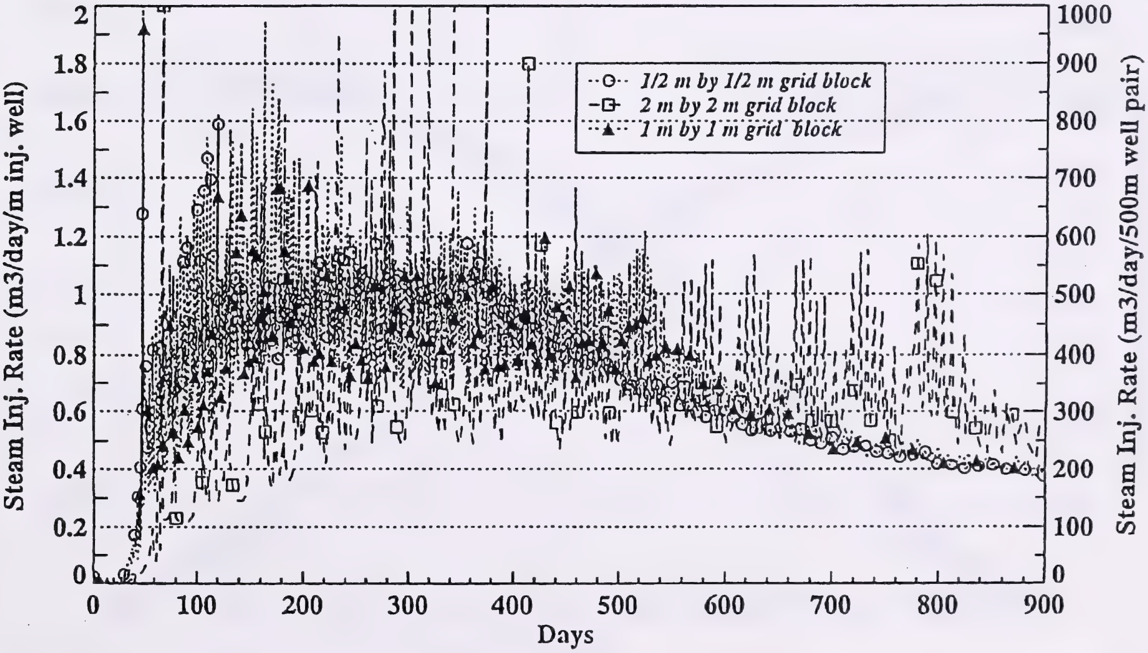


Figure 1.2 — Grid Block Size Sensitivity — Effects on Steam Rates

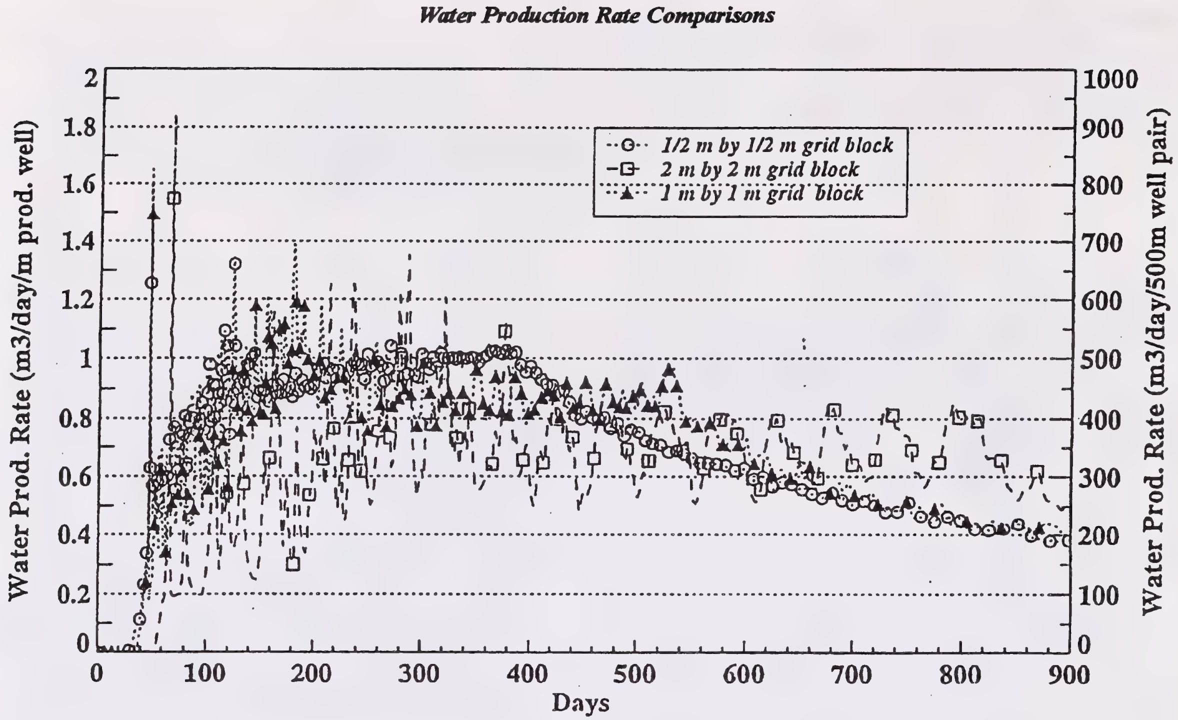


Figure 1.3 — Grid Block Size Sensitivity — Effects on Water Rates

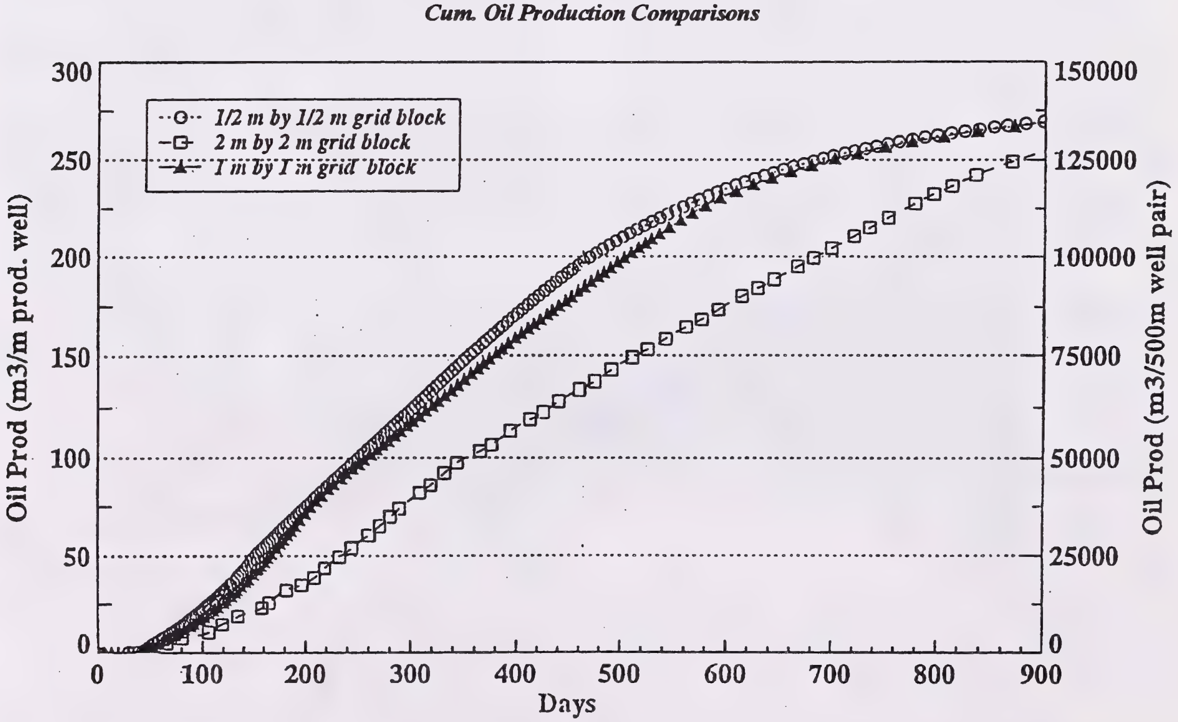


Figure 1.4 — Grid Block Size Sensitivity — Cum. Oil

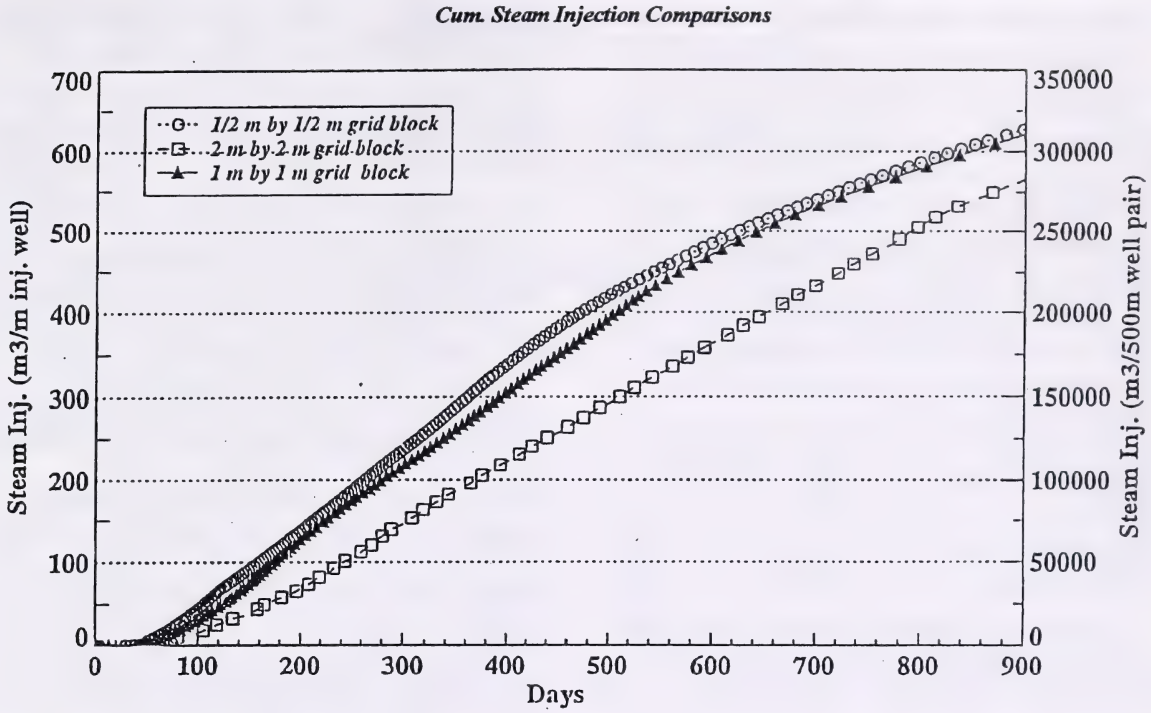


Figure 1.5 — Grid Block Size Sensitivity — Cum. Steam

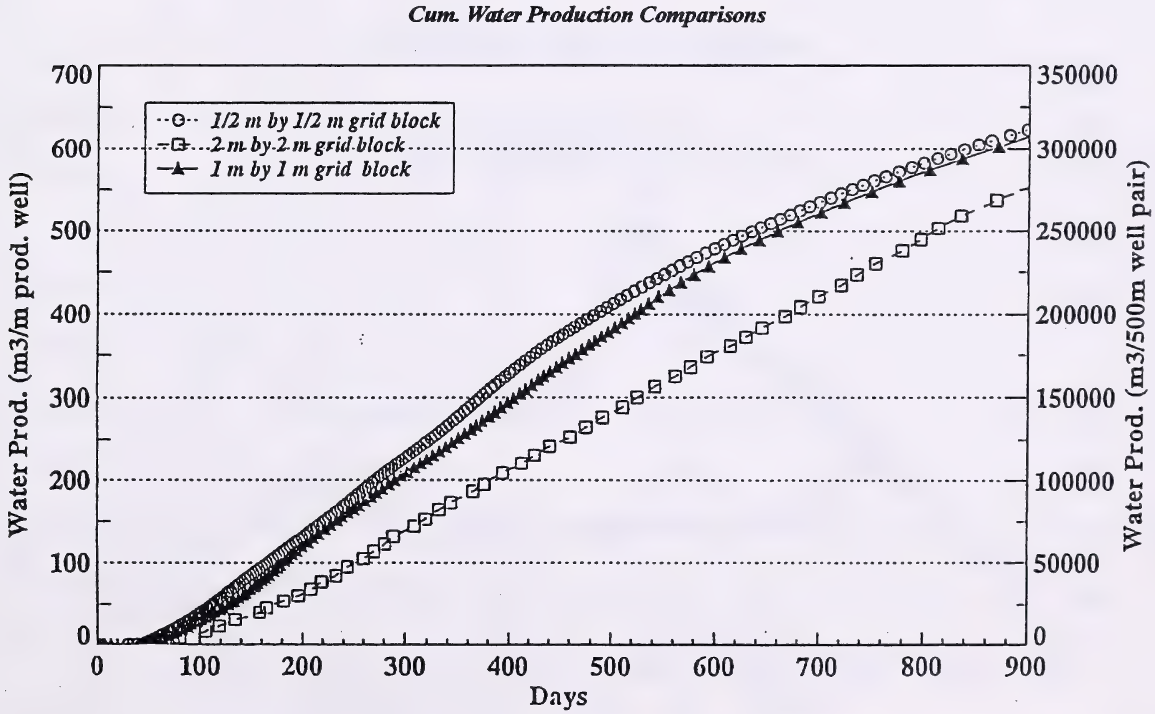


Figure 1.6 — Grid Block Size Sensitivity — Cum. Water

2) Effects of formation thickness

Compared to base case, increasing the formation thickness from 20 m to 40 m almost doubled oil production (see Figure 2.1), while the cumulative SOR was also slightly reduced due to less heat loss to overburden. Oil rate peaked at around 400 days for the 40 m thick formation whereas it peaked at 200 days for the 20 m thick formation. For both cases peak oil rates all occurred at points where the steam chambers reached the ceiling of the formations. The upward growth rates of the steam chambers for both cases were very much the same, and so were the lateral spreading rates (see Figure 2.3 and Figure 2.4). For high permeability reservoirs the oil productions seemed to be in proportion to their formation thickness.

(High Permeability 5 m inter-well spacing 2700 kPa)	Year	CDOR (m^3/d/ well-pair)	CSOR (m^3/m^3)	Recovery %
Base Case (20 m thick)	2.5	165.42	2.25	72%
40 m thick formation	2.5	338.60	1.79	73%

However, the conclusions reached above did not apply to a lower permeability formation where the permeabilities were reduced to 10 percent of the base case values.

(Low Permeability 5 m inter-well spacing 2700 kPa)	Year	CDOR (m^3/d/ well-pair)	CSOR (m^3/m^3)	Recovery %
20 m thick formation	4.0	40.34	3.06	28%
40 m thick formation	4.0	38.76	3.05	14%
	10.0	46.35	3.13	40%

Using these lower permeabilities, Kh = 1 D, Kv = 0.5 D, the oil production rates from a 40 m thick formation were hardly more than those of a 20 m thick formation (see Figure 2.2). The rates only lasted longer for the 40 m thick formation simply because it contained more reserves.

In theory, if gravity is the only driving force, higher drainage height should mean more drainage rates. The exact reason for the contradictory results from the low permeability runs was not very clear at this stage. However, in observation of the steam chamber profiles (see Figure 2.5), the lateral advancement of the steam chamber was severely limited in the low permeability reservoir for the entire simulation time of 10 years. Counter-current flow of the steam and oil was suspected to be more severe for low permeability reservoirs. Due to the very low effective permeabilities, gravity force alone seemed insufficient for the liquid to drain effectively to the producer. Methods of enhancing the process in the low permeability formations will be discussion in later sections.

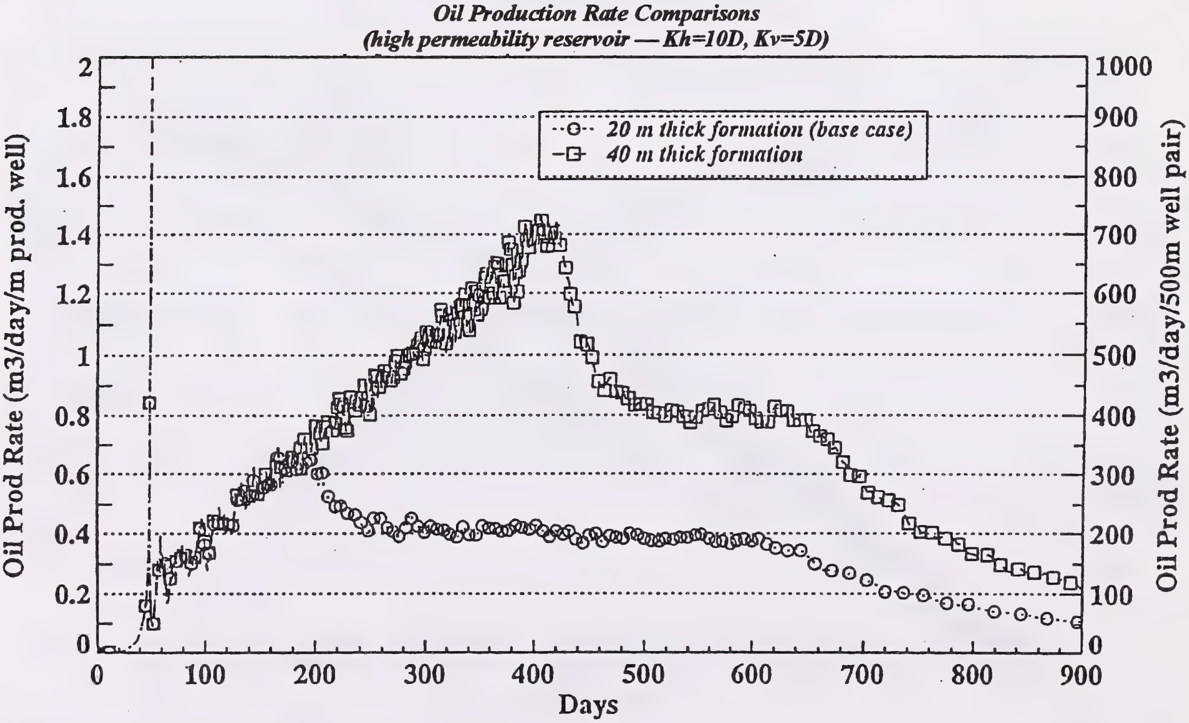


Figure 2.1 — Effects of Formation Thickness — Oil Rate

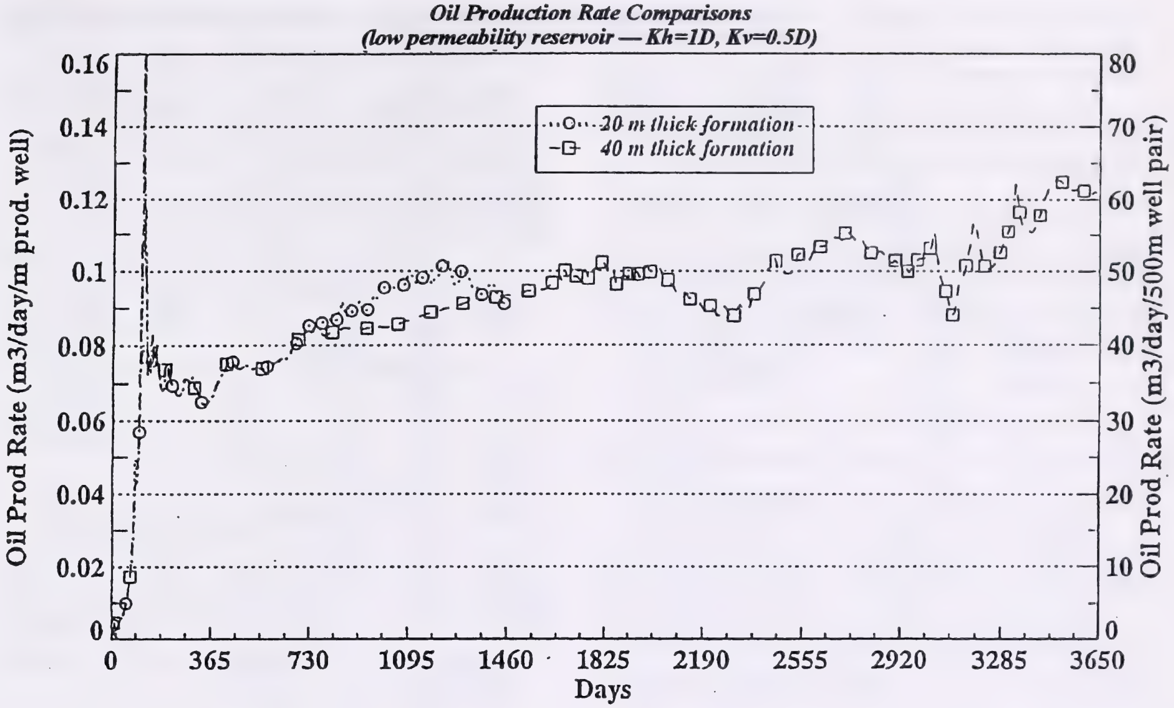


Figure 2.2 — Effects of Formation Thickness — Low Permeability

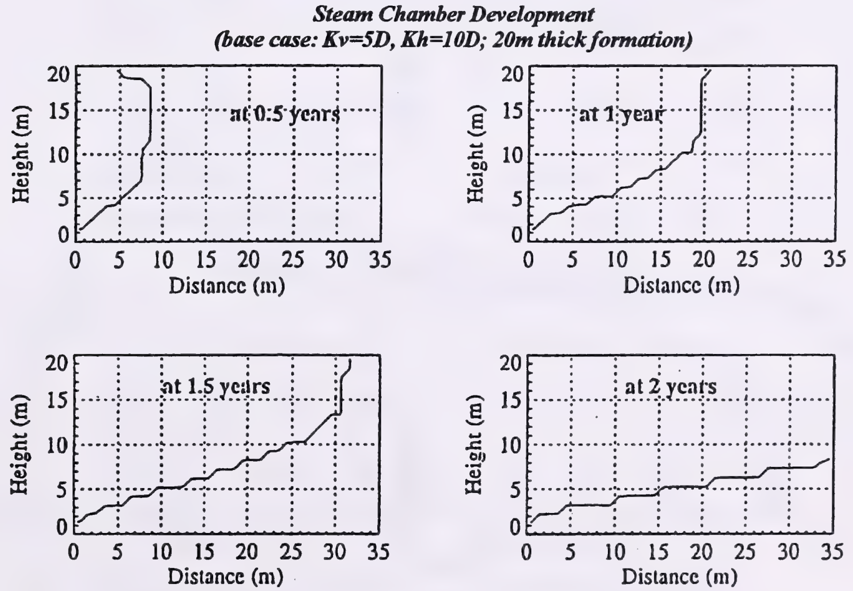
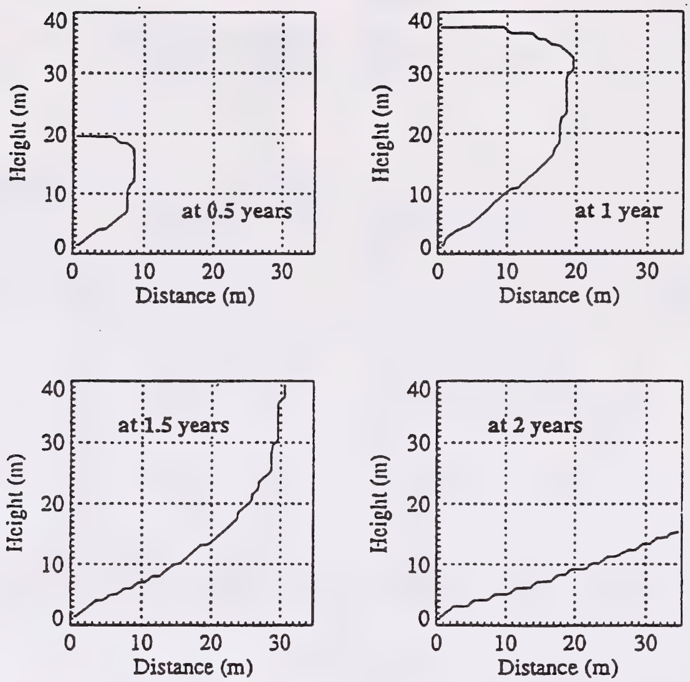
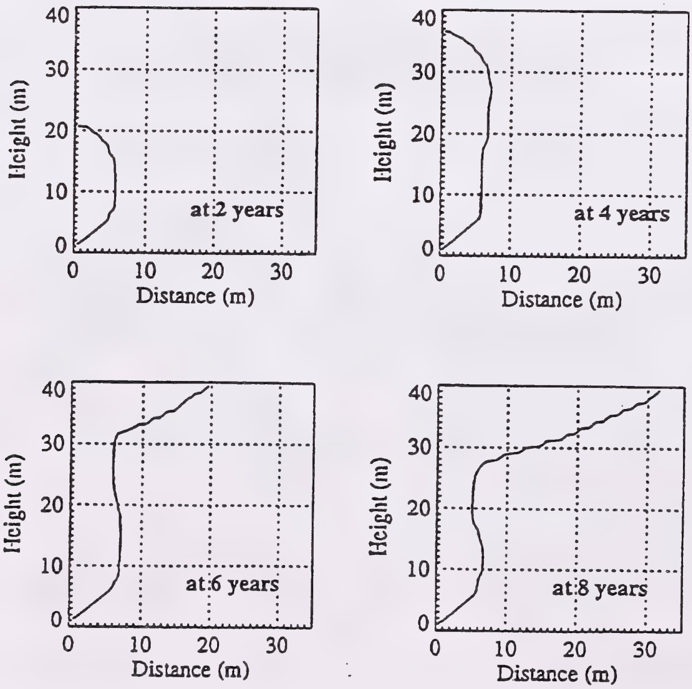


Figure 2.3 — Base Case Steam Chambers



Steam Chamber Development
(Kv=5D, Kh=10D; 40m thick formation)

Figure 2.4 — Thick Formation Steam Chambers



Steam Chamber Development
(Kv=0.5D, Kh=1D; 40m thick formation)
(2700 kPa, 5m inter-well spacing)

Figure 2.5 — Thick Formation — Low Permeability

3) Effects of injector/producer inter-well spacing

A 5-meter inter-well spacing between the injector and the producer was used as a standard for most of the runs performed. Compared to base case (5-meter inter-well spacing), an increased (10 m) inter-well spacing delayed the breakthrough between the injector and the producer from about 50 days to almost 200 days (see Figure 3.1). No other significant differences were observed except for the delayed start-up for the increased inter-well spacing case.

(High Permeability 20 m thick formation 2700 kPa)	Year	CDOR (m³/d/ well-pair)	CSOR (m³/m³)	Recovery %
5 m spacing	2.5	165.42	2.25	72%
10 m spacing	2.5	152.70	2.08	67%
	3.0	139.13	2.23	73%

The rates in terms of steam injection, water production, and oil production were all very similar for both cases immediately after the start-ups. The delayed oil production of the larger inter-well spacing case was compensated by its extended production beyond the production decline point of the base case (5-meter spacing case). Based on this result and those from Section 2, regarding formation thickness, it could be concluded that for a high permeability formation the oil rates were mainly functions of the gravity drainage height (formation height). The inter-well spacing, or the injection location in the reservoir, only affected the start-up time. No advantages were achieved by injecting higher in this higher permeability formation.

As was mentioned previously in Section 2, thicker formation did not achieve more oil rates for low permeability cases. However, oil rates in a low permeability formation benefited by an increased inter-well spacing (see Figure 3.2).

(Low permeability 40 m thick formation 2700 kPa)	Year	CDOR (m³/d/ well-pair)	CSOR (m³/m³)	Recovery %
5 m spacing	10.0	46.35	3.13	40%
10 m spacing	10.0	62.19	2.50	54%

On a 10-year basis the 10 m spacing case produced much more oil than the 5 m spacing case did, with average rates of 62 m³/d and 46 m³/d respectively, although it took more than a year to start up the larger spacing case. The steam chambers of the larger spacing case showed significant lateral advancements; compare Figure 3.3 to Figure 2.5.

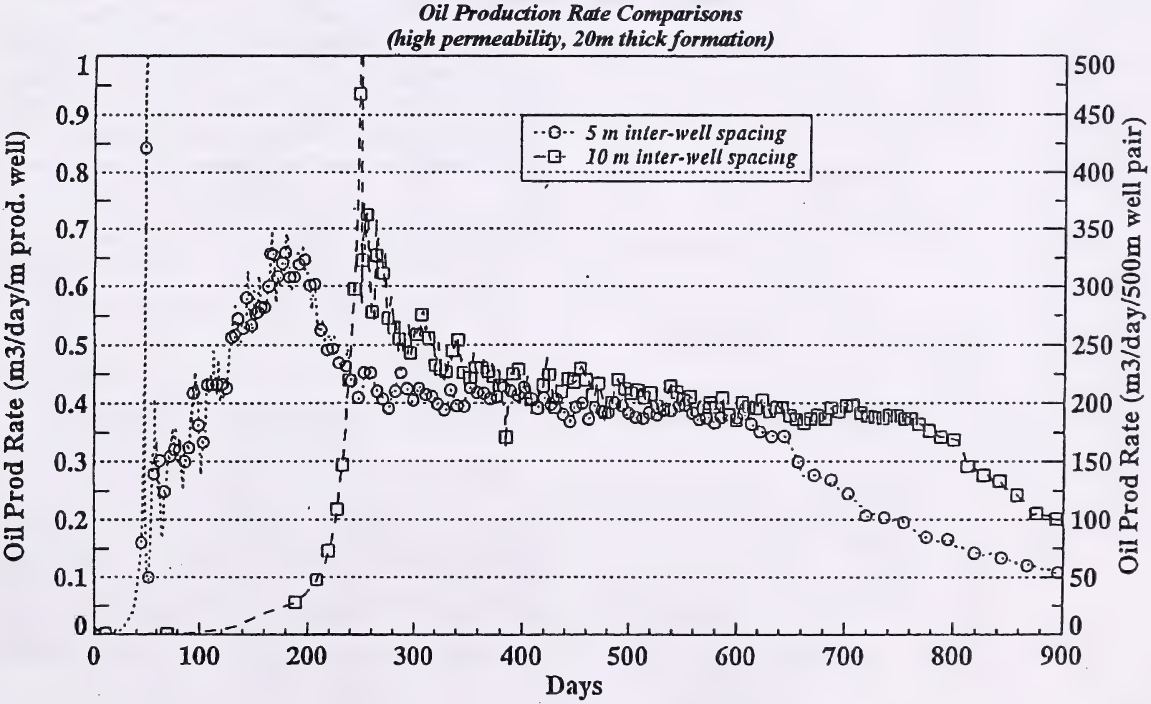


Figure 3.1 — Effects of Inter-well Spacing — high permeability

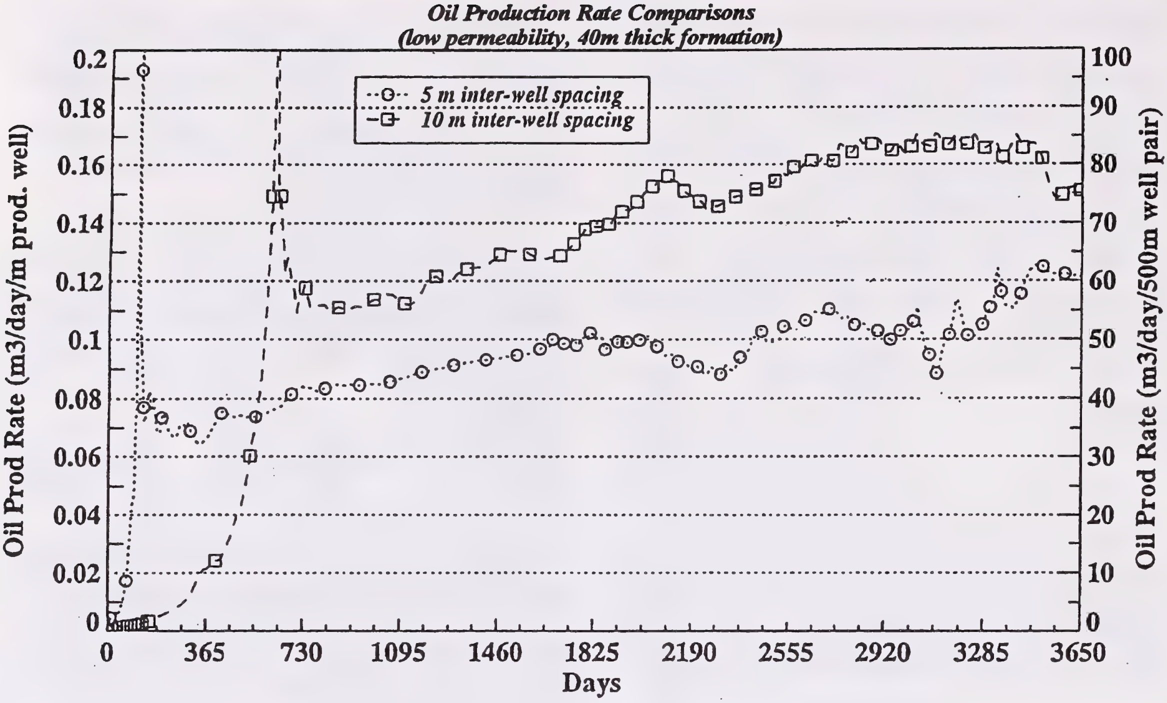


Figure 3.2 — Effects of Inter-well Spacing — low permeability

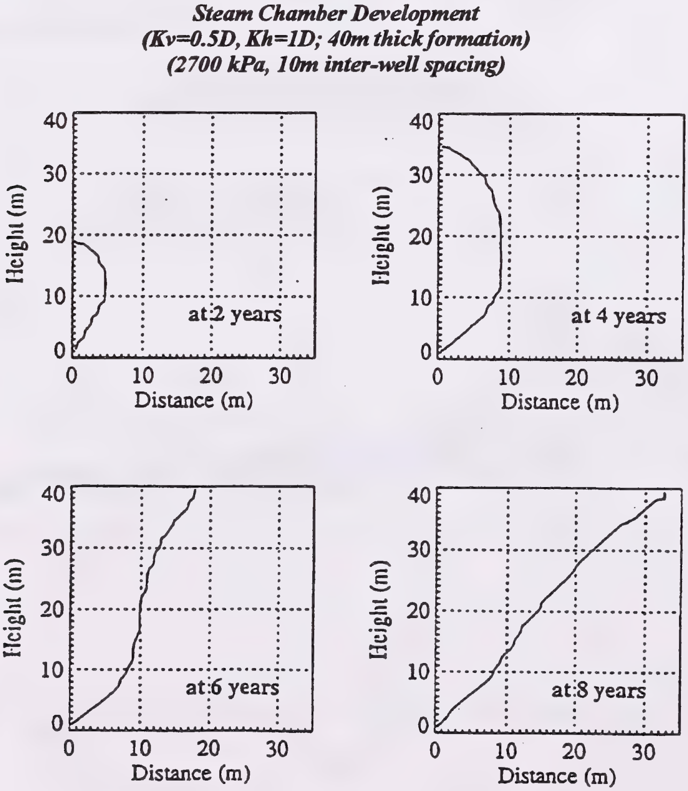


Figure 3.3 — Low Permeability — Larger Spacing

4) Effects of absolute permeabilities

a) Effects of vertical permeability (horizontal permeability remains the same at 10 Darcy)

By lowering the vertical permeability from 5 Darcy of the base case to 0.5 Darcy while keeping the horizontal permeability unchanged as of 10 Darcy, the CDOR at 2.5 years dropped from 165 m^3/d of the base case to 56 m^3/d; the CSOR increased from 2.25 to 2.63, as was shown in the following table:

(Kh = 10 Darcy 20 m thick formation 2700 kPa)	Year	CDOR ($m^3/d/$ well-pair)	CSOR (m^3/m^3)	Recovery %
Kv = 5 Darcy	2.5	165.42	2.25	72%
Kv = 0.5 Darcy	2.5	56.00	2.63	24%
	4.0	60.80	2.74	42%

The oil rate comparisons were in Figure 4.1. It seemed quite obvious that vertical permeabilities mainly controlled the oil production rates, but its effects on CSOR were relatively small. Compared to base case steam chambers in Figure 2.3, the lower vertical permeability restricted both the vertical and horizontal growth rate of the chamber (see Figure 4.4), although the horizontal permeability was the same as that of base case.

b) Effects of horizontal permeability (vertical permeability remains the same at 0.5 Darcy)

Following the discussions on vertical permeability effects, the effects of horizontal permeabilities were also investigated. The horizontal permeability of case a) was lowered from 10 Darcy to 1 Darcy. The cumulative results are shown in the following table while the oil rates are in Figure 4.2. The horizontal chamber growth was slightly slower (see Figure 4.5) while the vertical growth was not different from that of case a), as shown in Figure 4.4.

(Kv = 0.5 Darcy 20 m thick formation 2700 kPa)	Year	CDOR ($m^3/d/$ well-pair)	CSOR (m^3/m^3)	Recovery %
Kh = 10 Darcy	4.0	60.80	2.74	42%
Kh = 1 Darcy	4.0	40.34	3.06	28%

The effects of horizontal permeabilities were not as drastic as those of vertical permeabilities.

c) Effects of horizontal and vertical permeabilities

From base case, reducing both the horizontal and vertical permeabilities – Kh from 10 Darcy to 1 Darcy, Kv from 5 Darcy to 0.5 Darcy – resulted in significant reduction in oil rates (see Figure 4.3) and also in steam chamber growth rate (compare Figure 2.3 and Figure 4.5) and some increase in steam to oil ratio.

(20 m thick formation 2700 kPa	Year	CDOR ($m^3/d/$ well-pair)	CSOR (m^3/m^3)	Recovery %
Kh = 10 D, Kv = 5 D	2.5	165.42	2.25	72%
Kh = 1 D, Kv = 0.5 D	2.5	35.75	3.00	15%
	4.0	40.34	3.06	28%

In conclusion, vertical permeability affected oil rate more than that of horizontal permeability. Permeability effects on steam to oil ratio were relatively small.

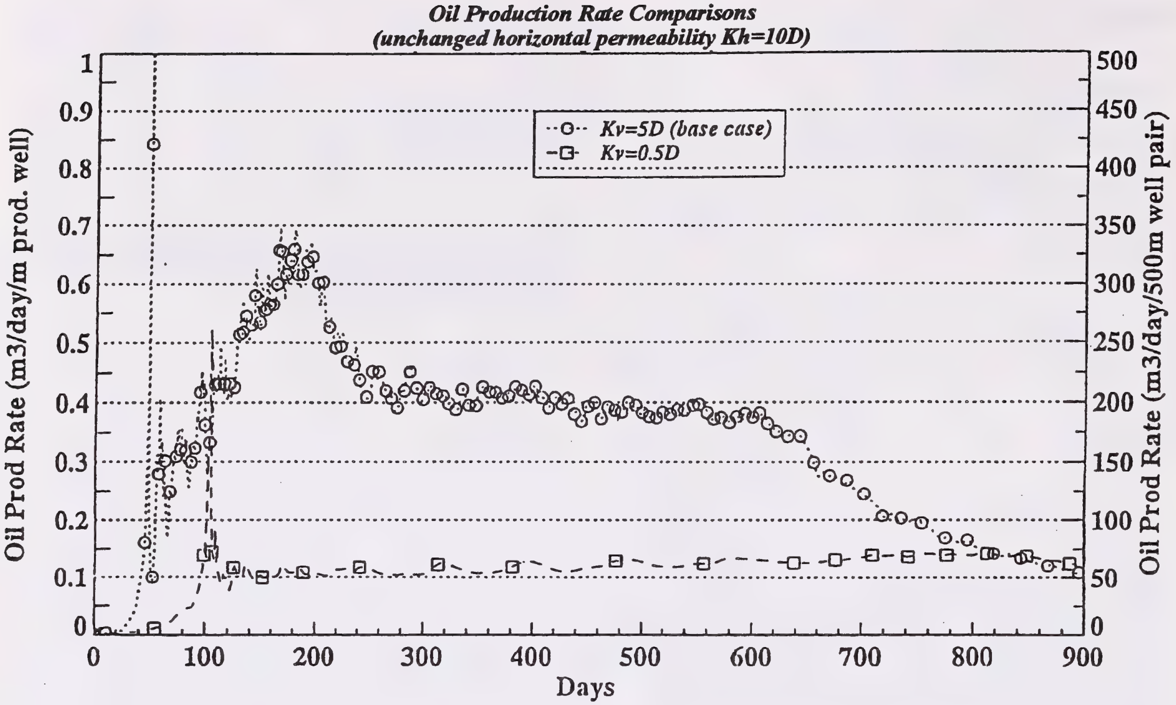


Figure 4.1 — Effects of Vertical Permeability — Oil Rate

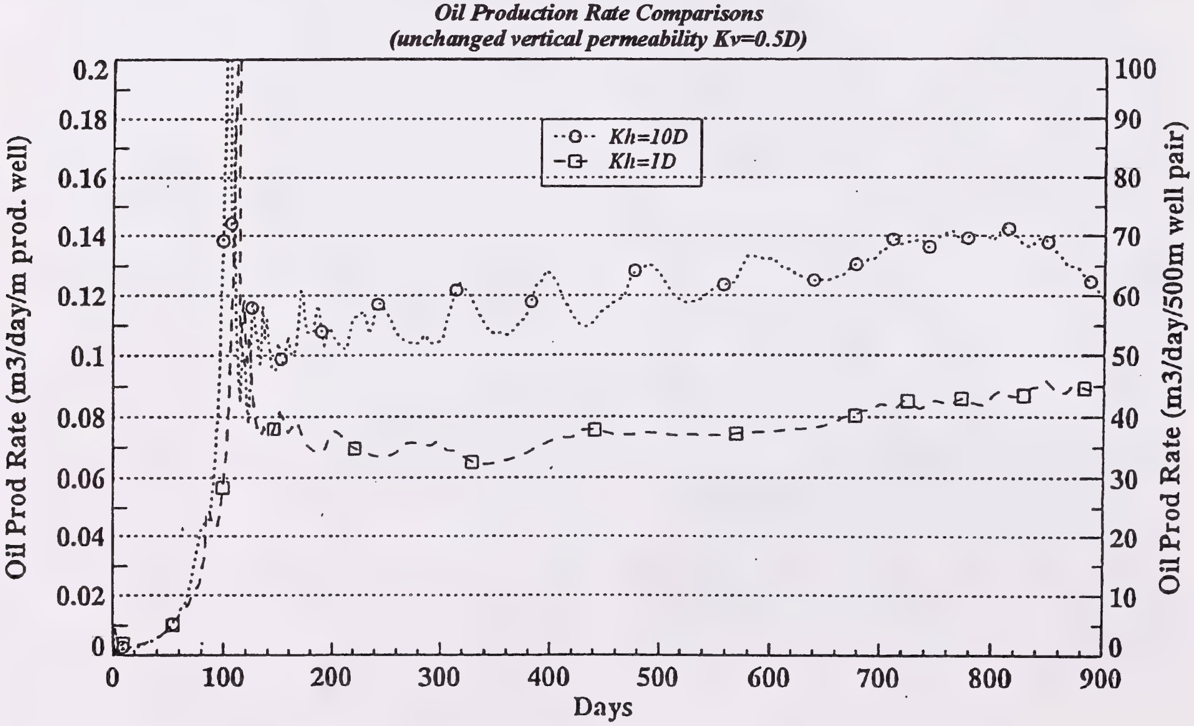


Figure 4.2 — Effects of Horizontal Permeability — Oil Rate

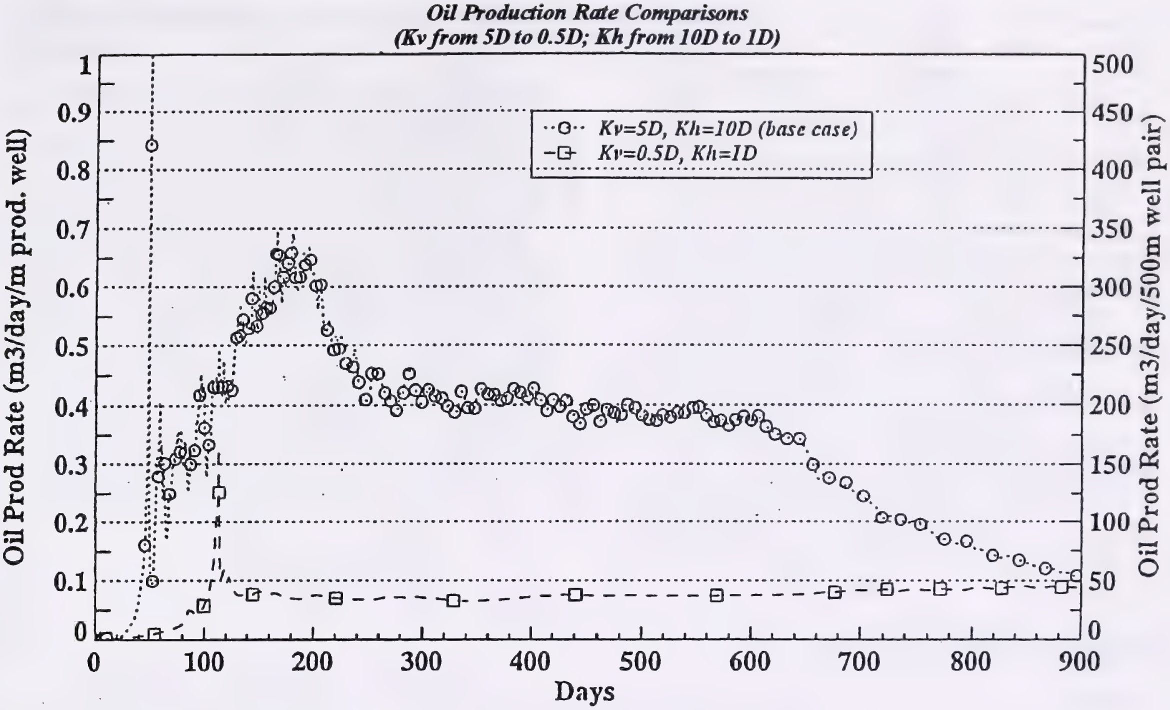


Figure 4.3 — Effects of Horizontal and Vertical Permeabilities

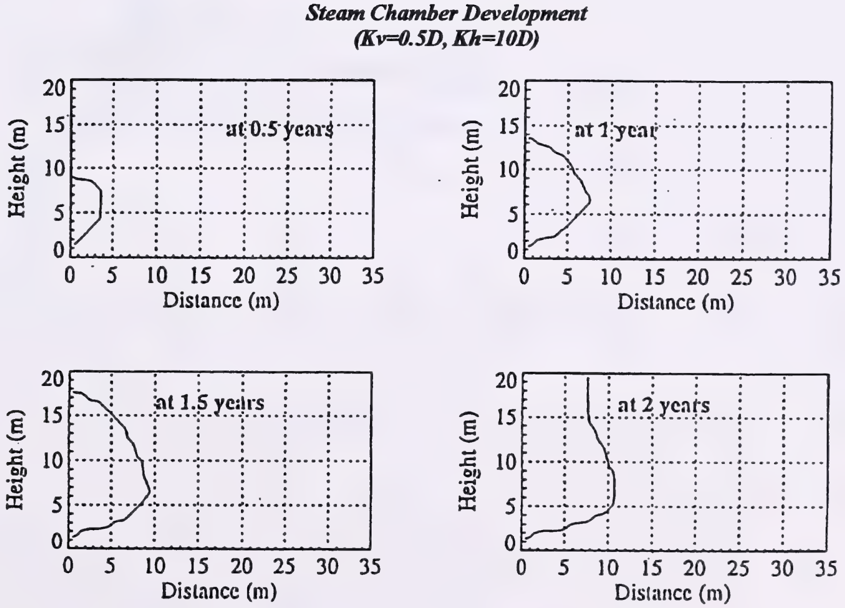
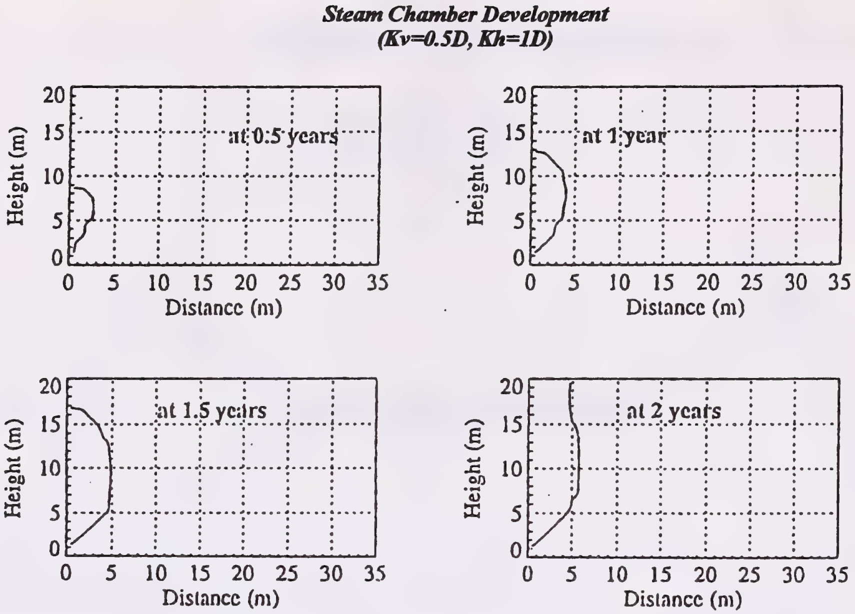


Figure 4.4 — Effects of Kv on Steam Chambers



Steam Chamber Development
(Kv=0.5D, Kh=1D)

at 0.5 years

at 1 year

at 1.5 years

at 2 years

Figure 4.4 — Effects of Kh on Steam Chambers

5) Effects of lower oil saturation (higher water saturation)

A lower oil saturation of 60% was used to study the effects of the higher water content in the formation. When the water saturation was high, the effects of connate water saturation (Swr) were also significant. The amount of mobile water, Sw-Swr, affected both the water production rate (see Figure 5.2) and the initial breakthrough time. If no mobile water was present in the formation – i.e., Sw-Swr = 0, such as the base case and the Sw = Swr = 40% case – the water production rates (Figure 5.2) followed very closely the steam injection rates (Figure 5.3). The higher water saturation with no mobile water case consumed almost the same amount of steam as the base case did but produced more water. By producing the similar amount of total fluids, the volumetrically less oil content in the formation resulted in less oil production rates, therefore higher SOR.

(High permeability 20 m thick formation 2700 kPa, 5 m spacing)	Year	CDOR (m^3/d/ well-pair)	CSOR (m^3/m^3)	Recovery %
Sw = 15%	2.5	165.42	2.25	72%
Sw = 40%	1.5	154.00	2.97	57%
	2.5	120.80	3.34	74%

Some formation might contain mobile water, where its initial formation water saturation was higher than its connate water saturation, Swr. This mobile water played an important role in early start-up phase. For cases with Sw = 40%, allowing 25% initial mobile water (Swr = 15%) present in the formation resulted in almost immediate breakthrough between the injector and the producer (see Figure 5.1). And the subsequent high water production rates also required excessive steam injection (see Figures 5.2 and 5.3). Unfortunately, this excessive steam injection did not bring up any more oil production (see Figure 5.1).

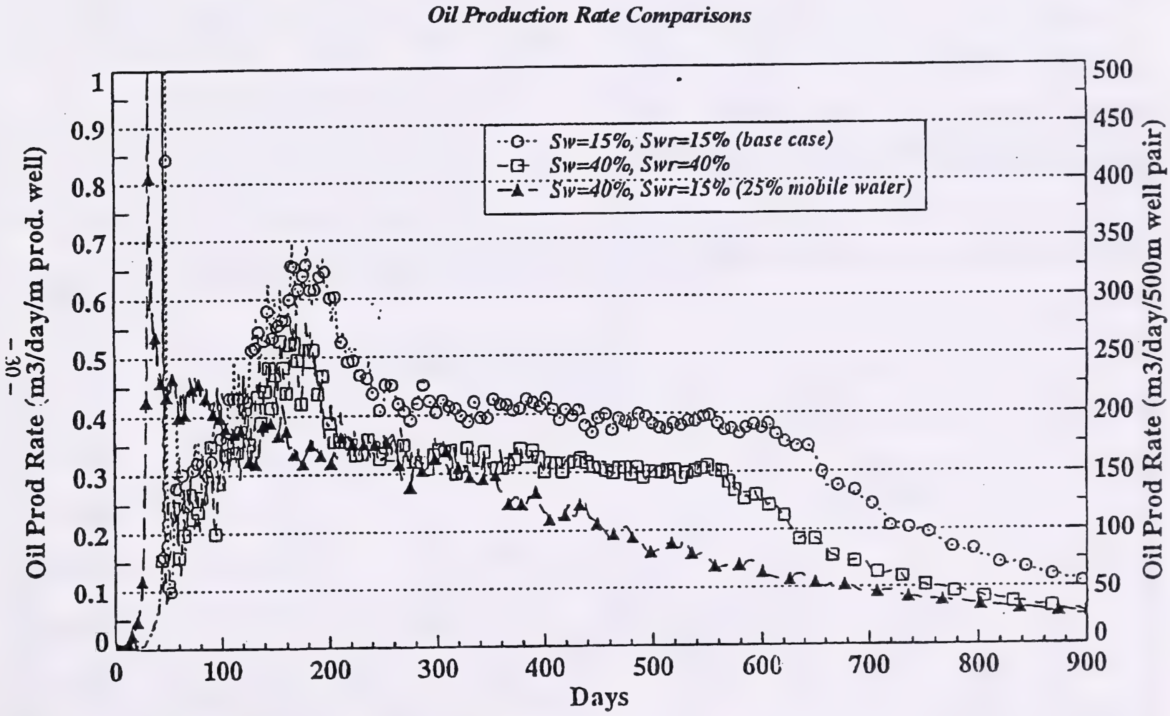


Figure 5.1 — Effects of Water Saturations on Oil Rates

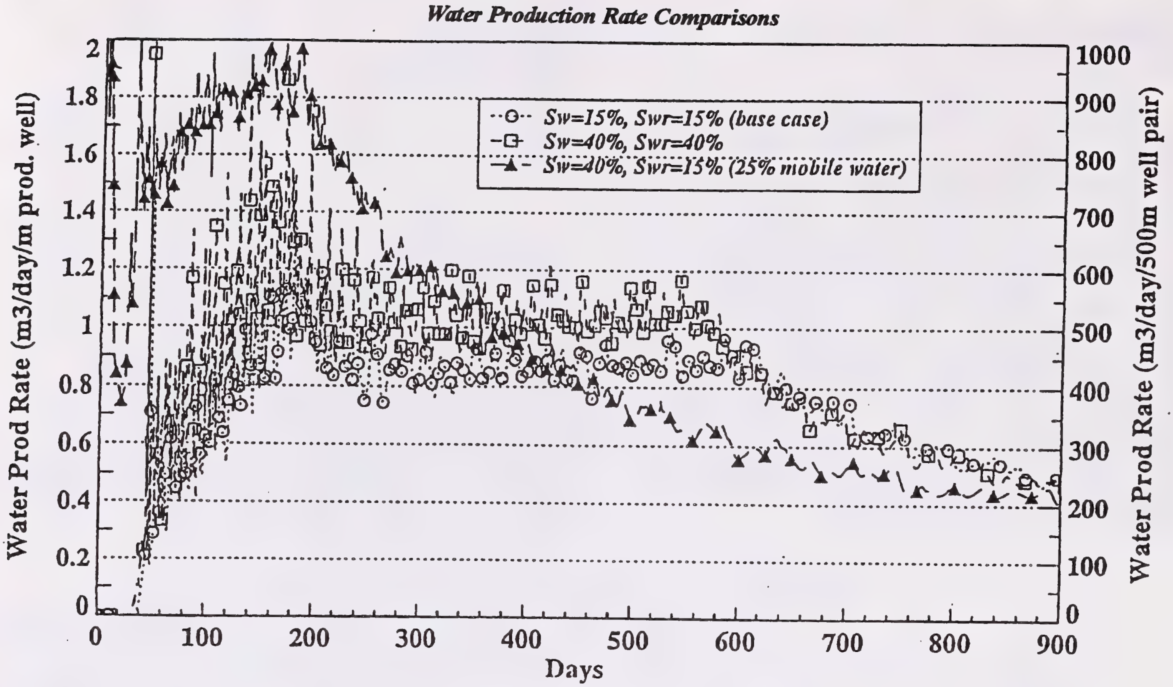


Figure 5.2 — Effects of Water Saturations on Water Rates

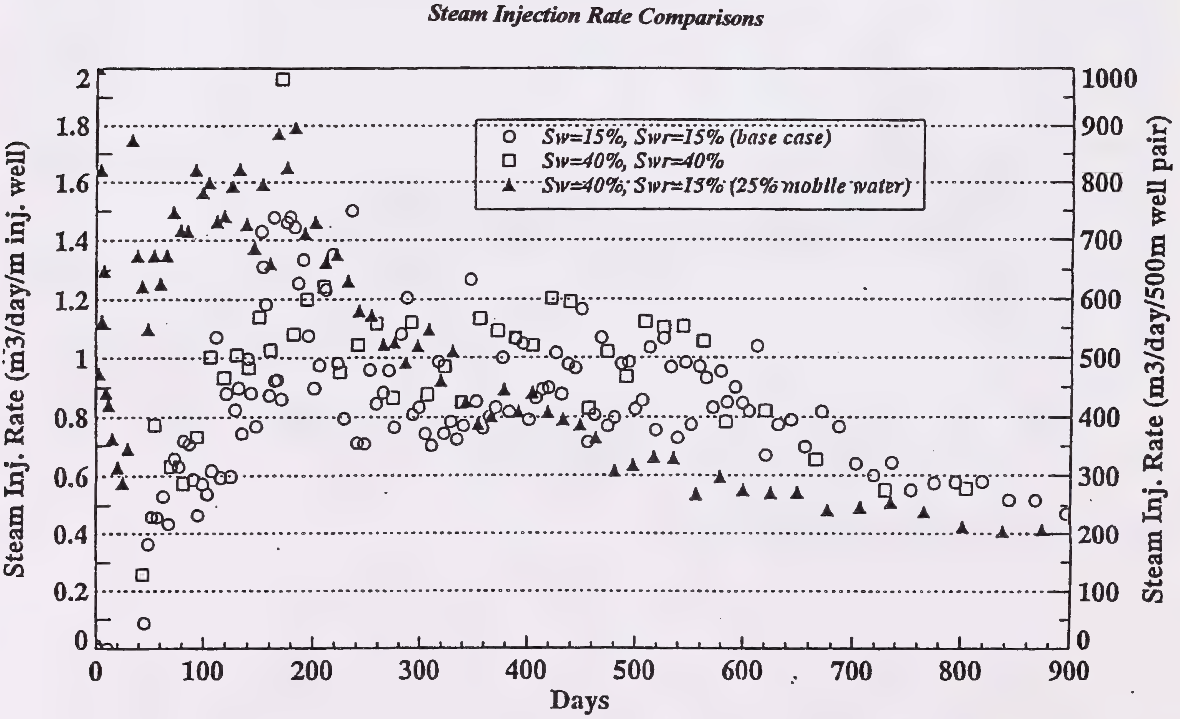


Figure 5.3 — Effects of Water Saturations on Steam Rates

6) Effects of wettability

The wettability is reflected on the relative permeability at residual oil saturation: as Krw at residual oil decreases, the formation becomes more water wet in general. Based on this, Krw at residual oil saturation was varied to test the effects of relative permeability to water (i.e., wettability) on SAGD process. All the cases used the same liquid (oil)-gas relative permeability curves as in Figure 6.1, with only the relative permeability to water, Krw, varied to represent oil-wet and water-wet cases (see Figure 6.2). The base case Krw was somewhere in the middle. The results shown in the following table and also in Figure 6.3 to Figure 6.5 indicated that oil-wet formations performed better than water-wet.

All the relative permeability to water values, Krw, reference a residual oil saturation of So = 20%:

(High permeability 20 m thick formation 2700 kPa, 5 m spacing)	Year	CDOR (m^3/d/ well-pair)	CSOR (m^3/m^3)	Recovery %
oil-wet (Krw = 0.95)	2.0	233.28	1.92	81%
base case (Krw = 0.45)	2.5	165.42	2.25	72%
water-wet (Krw = 0.04)	2.5	136.93	2.27	60%

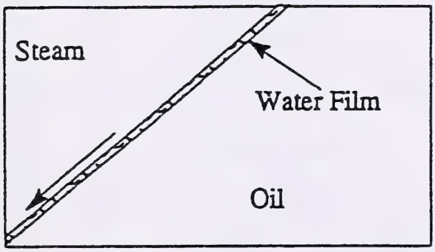
If water was used as a main driving force, such as in water flood, strong water wet (low Krw) formation normally would benefit oil rates. However, the above test results show the opposite trend for SAGD. Less water-wet (more oil-wet) indicated better oil rate with even improved steam to oil ratio.

The SAGD oil rate was very closely related to its steam chamber growth rate. The low Krw, i.e., water-wet, seemed to restrict this growth.

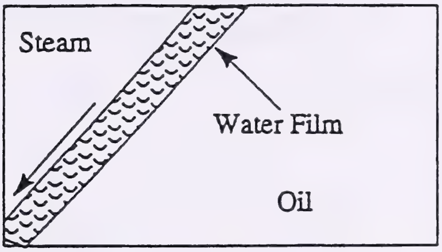
Ahead of the steam chamber there always existed a thin steam condensate layer, or water film. This water film tended to go thicker as the wettability to water became stronger. Strong water-wet could be numerically translated as high residual water saturation and low effective permeability to water. Both these effects slowed down the drainage or removal of this water film and, as a result, restricted the conductive heating and steam interface advancing rate, which is proportional to the oil drainage rate.

Figures 6.6, 6.7, and 6.8 show the water saturation profiles of the oil-wet case, base case, and water-wet case respectively. No higher water saturation was observed in the oil-wet case (see Figure 6.6) while a water film of 40% water stayed ahead of the steam chamber in the water-wet case throughout the entire drainage phase (see Figure 6.8).

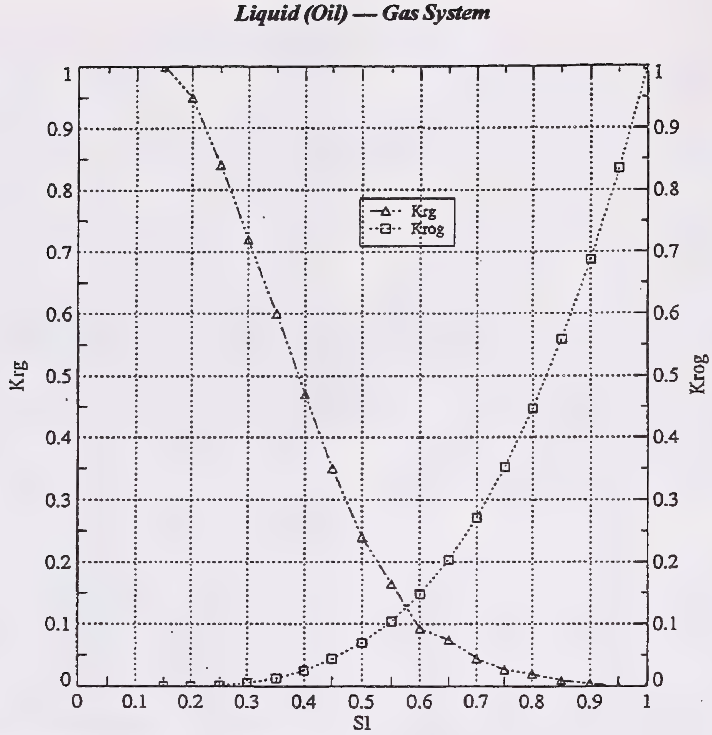
For conventional driving processes, water flood for instance, major oil recovery was normally achieved before breakthrough of the driving fluid to the producer. As a matter of fact, breaking through should be delayed for as long as possible, which also meant that a water-wet formation (low permeability to water) would achieve better oil recovery. For a SAGD process, however, established breakthrough only acts as a starting point for gravity drainage. Therefore, oil-wet formations (high permeability to water) would be more favourable candidates for SAGD processes. Higher permeability to water allows earlier breakthrough as well as faster steam chamber growth. The sooner the breakthrough, the earlier the drainage will start. The faster the steam chamber growth is, the better the oil rate will be.



Oil Wet Formation

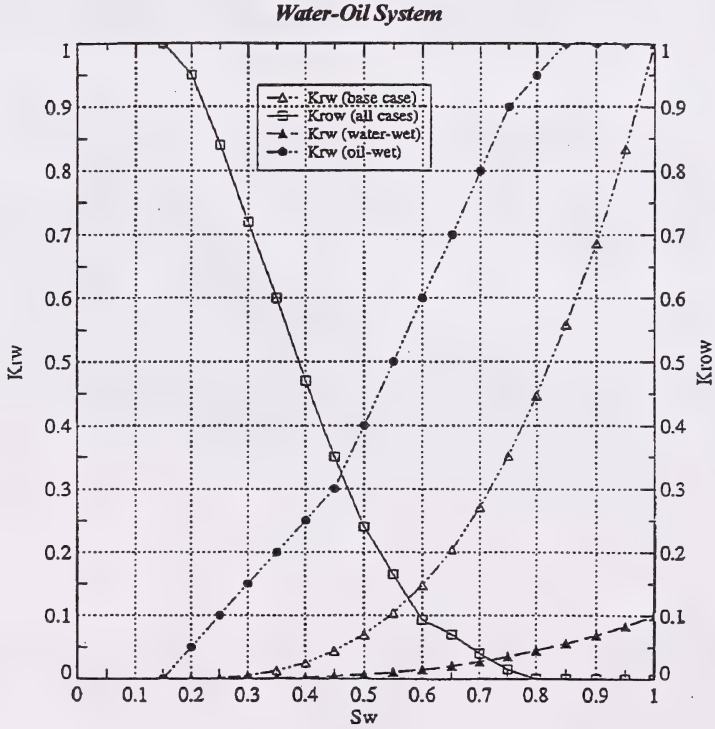


Water Wet Formation



Liquid (Oil) — Gas System

Figure 6.1 — Relative Permeability Curves — Liquid-Gas



Water-Oil System

Figure 6.2 — Relative Permeability Curves — Water-Oil

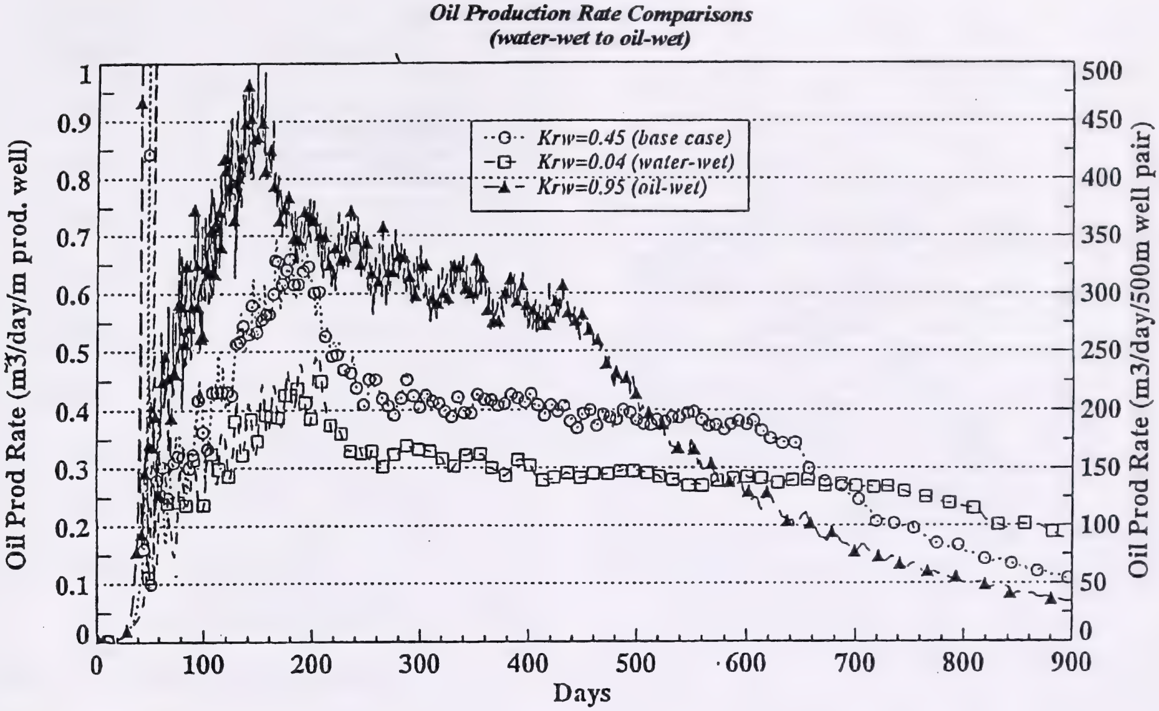


Figure 6.3 — Effects of Wettability on Oil Rates

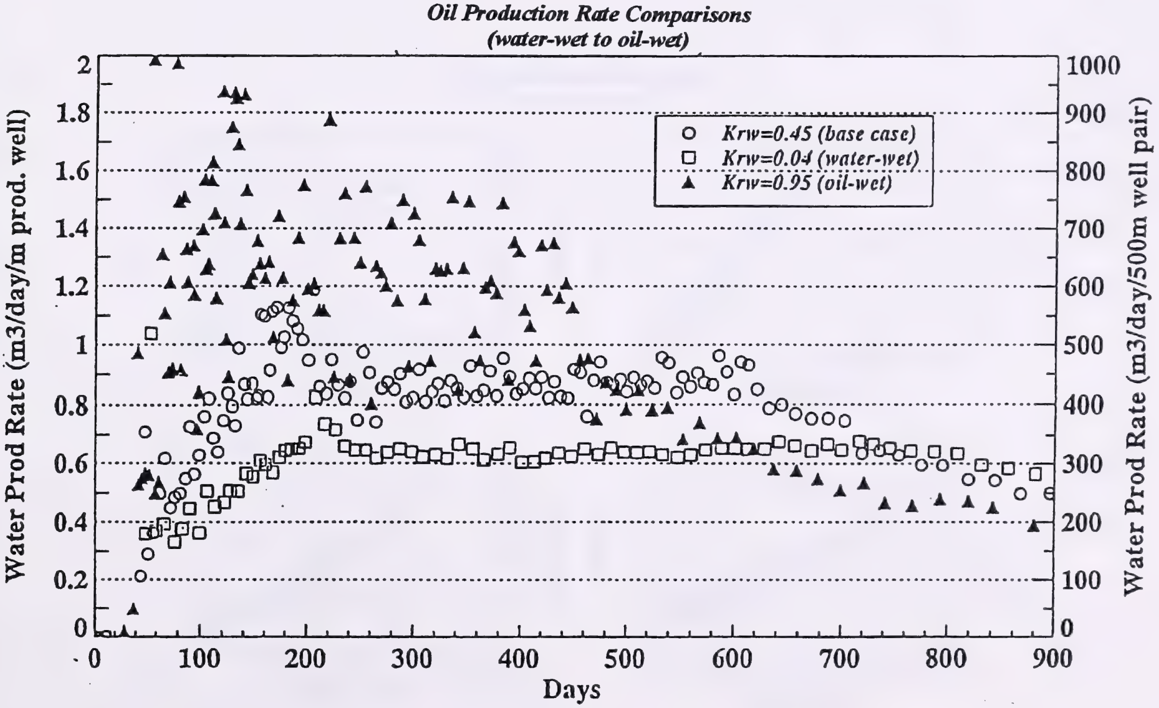


Figure 6.4 — Effects of Wettability on Water Rates

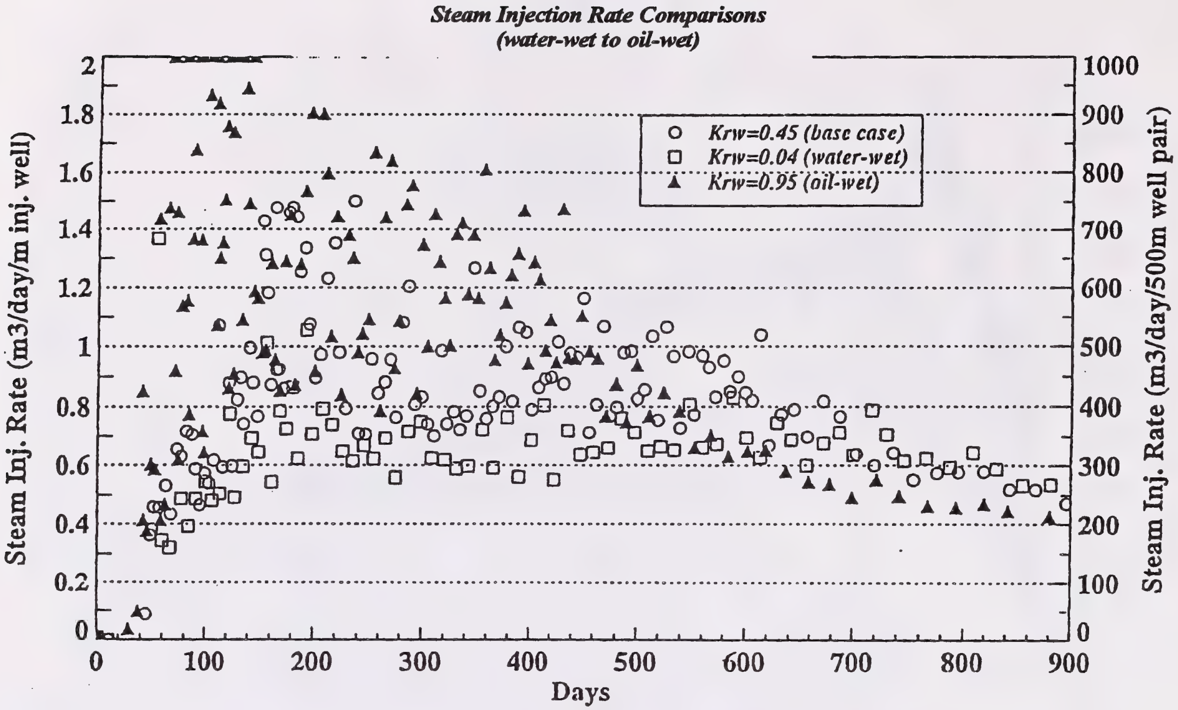

Steam Injection Rate Comparisons
(water-wet to oil-wet)

Figure 6.5 — Effects of Wettability on Steam Rates

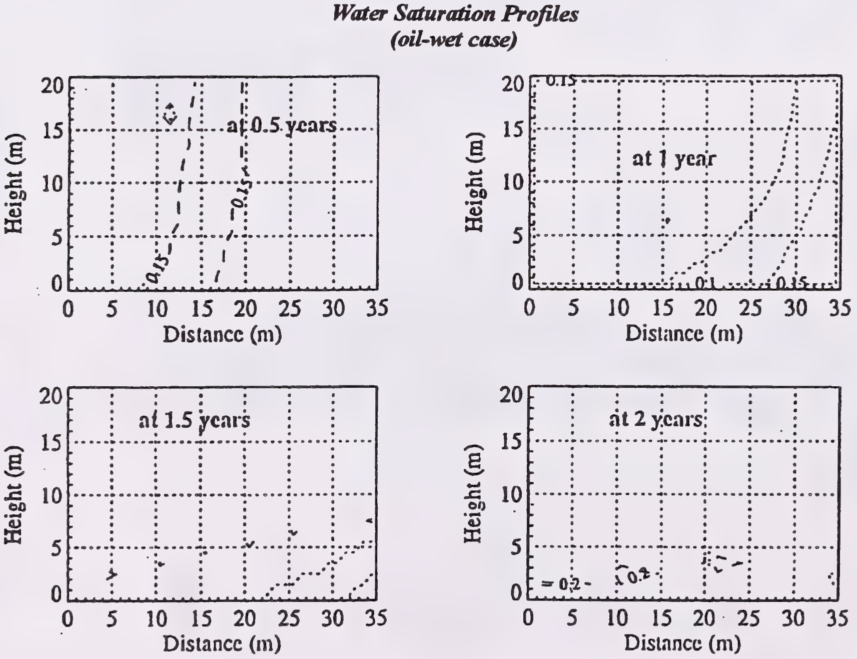

Water Saturation Profiles
(oil-wet case)

Figure 6.6 — Oil-wet Case — Water Saturations

Water Saturation Profiles
(base case)

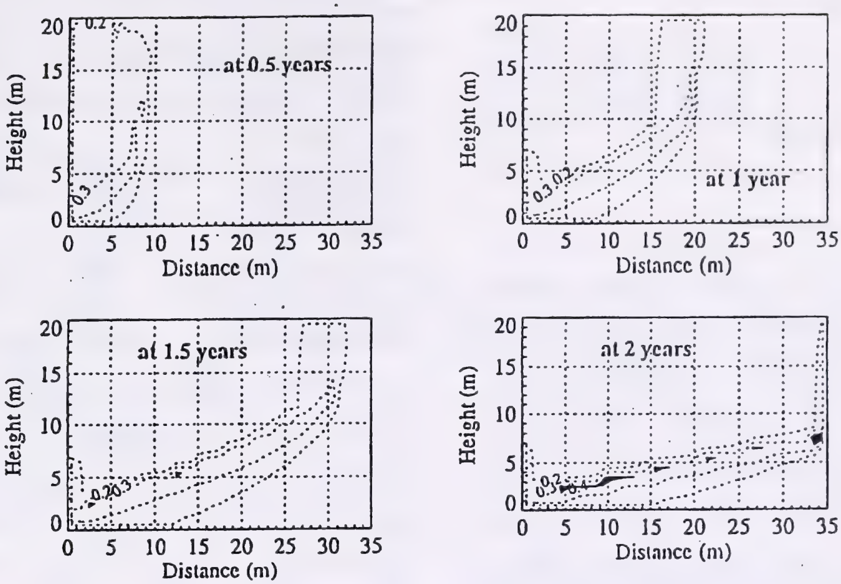


Figure 6.7 — Base Case — Water Saturations

Water Saturation Profiles
(water-wet case)

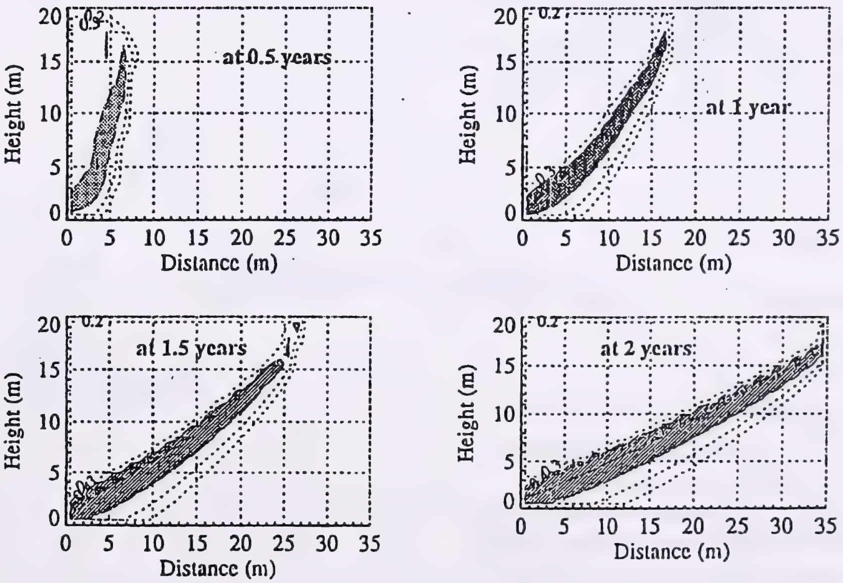
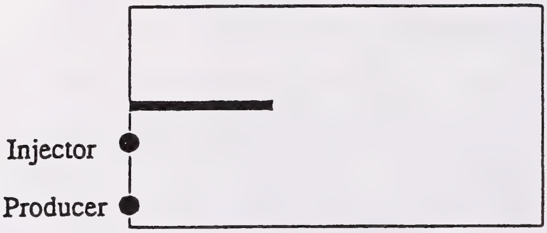


Figure 6.7 — Water-wet Case — Water Saturations

7) Effects of tight streaks

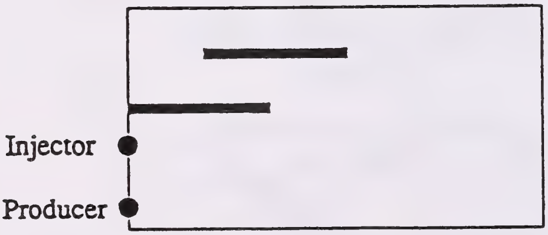
a) one tight streak



A 10 meter long by 1 meter thick tight streak, with zero porosity and zero permeability, right above the well pair did not affect the cumulative performance. Its effects on instantaneous rates were also very predictable (see Figure 7.1). Within the first 200 days, the steam chamber was below the streak; therefore, the stable oil rate was almost half of that of the no streak case, as if the formation was only 10 m thick instead of 20 m thick, and the streak was acting as the formation top. When the steam chamber passed around the streak and reached the second stable oil rate, the effects of the streak were no longer observable. This second stable oil rate was the same as the stable rate reached by the base case. The peak oil rate was slightly higher than that of the no streak case (base case). This was because the heat transferred through the streak during the first 200 days further mobilized the bitumen above the streak, and this mobilized bitumen was added to the peak rate as soon as the flow path to the producer was created. The steam chamber profiles are in Figure 7.4.

(High permeability 20 m thick formation 2700 kPa, 5 m spacing)	Year	CDOR ($m^3/d/$ well-pair)	CSOR (m^3/m^3)	Recovery %
base case (no streaks)	2.5	165.42	2.25	72%
one streak case	2.5	162.84	2.25	71%

b) two tight streaks



The first delay in oil rate (see Figure 7.2) was the same as that of case a). It was caused by the first streak right above the two wells. The second streak also delayed the oil rate but was very brief compared to the first delay. This was due to the fact that steam could go around the second streak on both sides and also that the second streak was farther away from the well pair. The rate then climbed to a peak which was higher than that of case a). The steam injections for both case a) and case b) were affected similarly as the oil rates were affected (see Figure 7.3). The cumulative steam injection and oil production were affected very little by these two streaks. The steam chamber profiles of this two-streak case are in Figure 7.5.

(High permeability 20 m thick formation 2700 kPa, 5 m spacing)	Year	CDOR ($m^3/d/$ well-pair)	CSOR (m^3/m^3)	Recovery %
base case (no streaks)	2.5	165.42	2.25	72%
two-streak case	2.5	161.75	2.28	70%

It seemed that although some tight streaks could affect the instantaneous rates, their impacts on cumulative performance were unlikely to be significant. A delay in the peak rate is significant even if the cumulatives are the same. In a commercial project designed to produce a certain total volume a day, the shift in peak rate means the project will not reach the full potential over that period. The streaks far away from the well pair would have less impact.

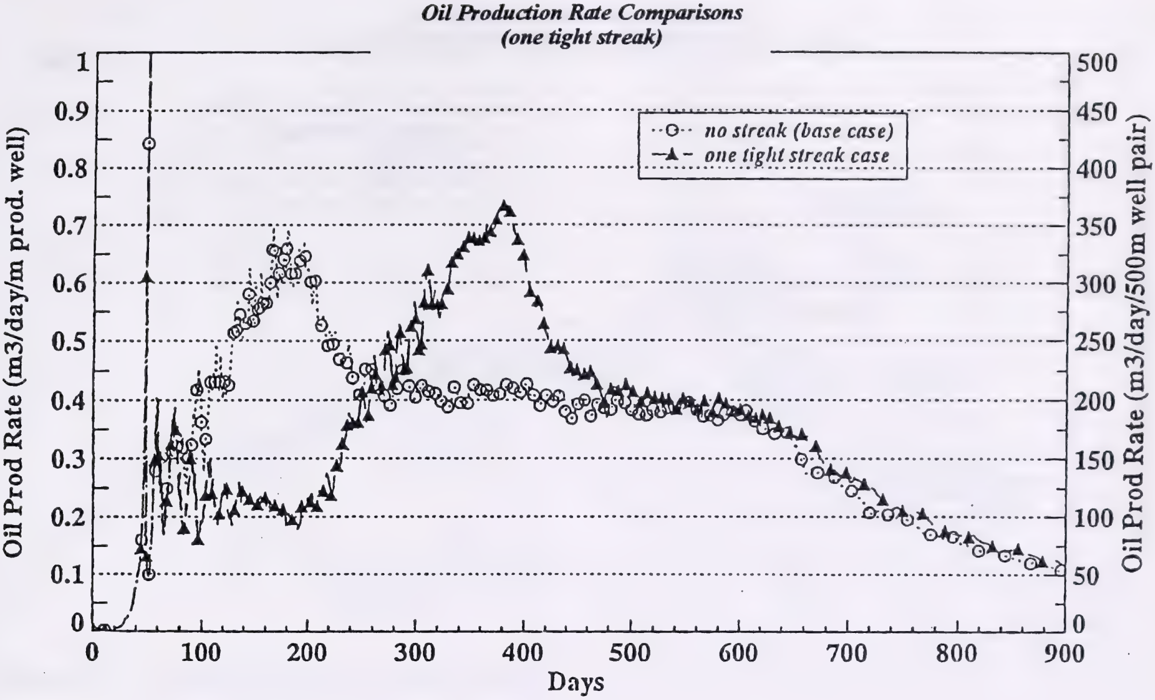


Figure 7.1 — Effects of a Tight Streak on Oil Rates

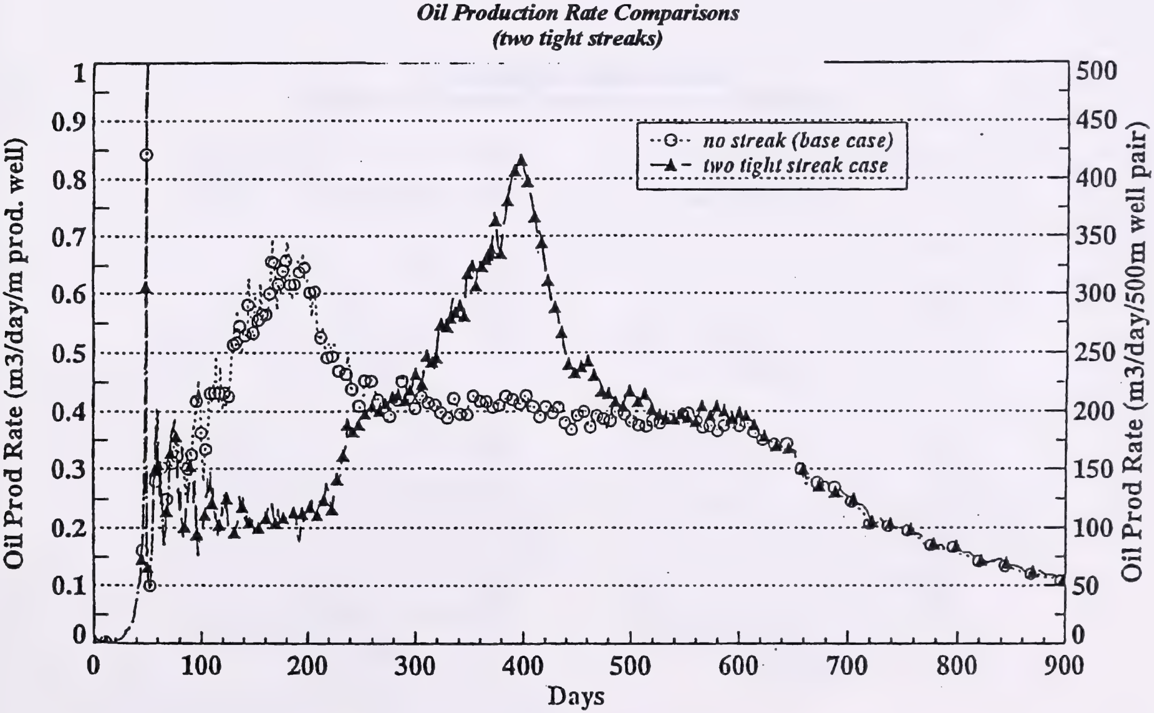


Figure 7.2 — Effects of Two Tight Streaks on Oil Rates

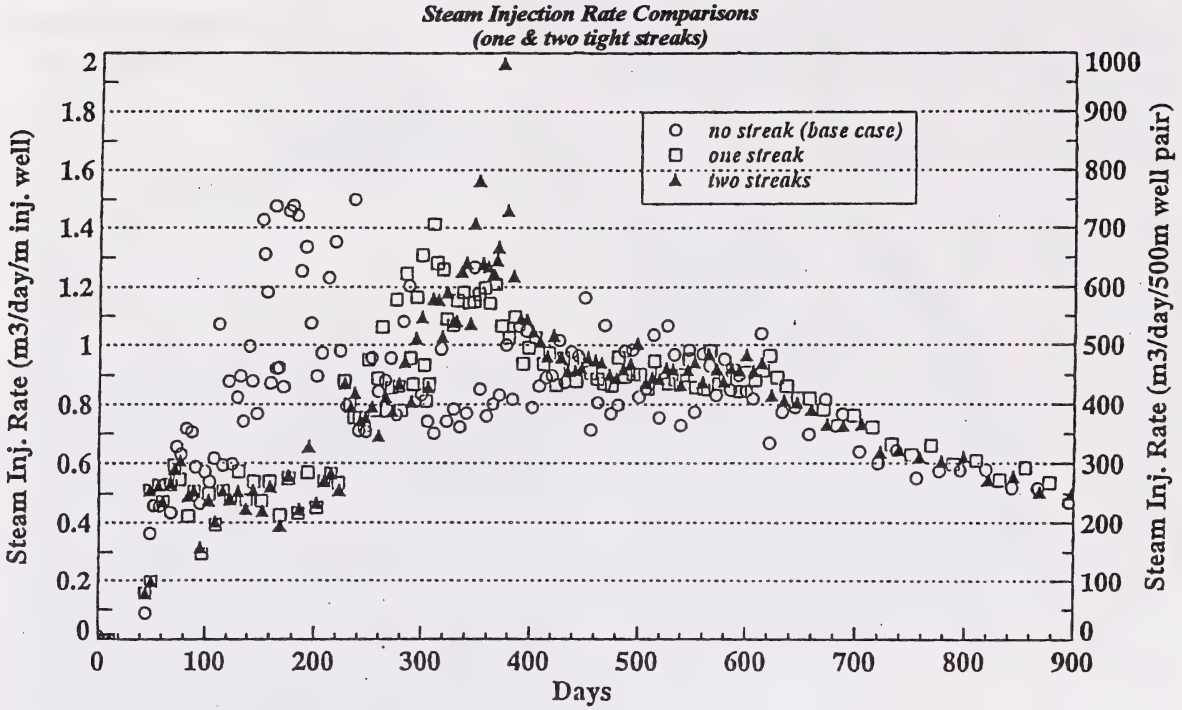


Figure 7.3 — Effects of Tight Streaks on Steam Rates

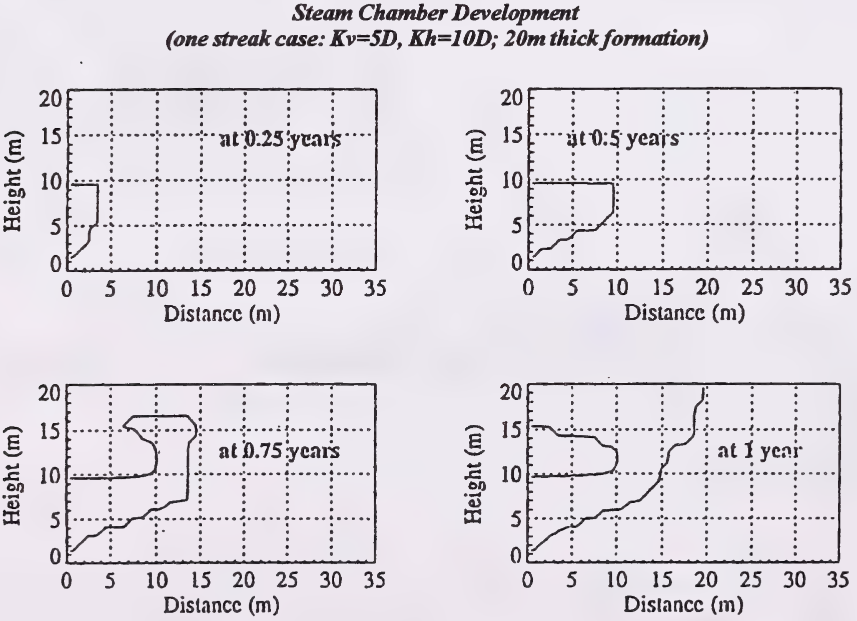
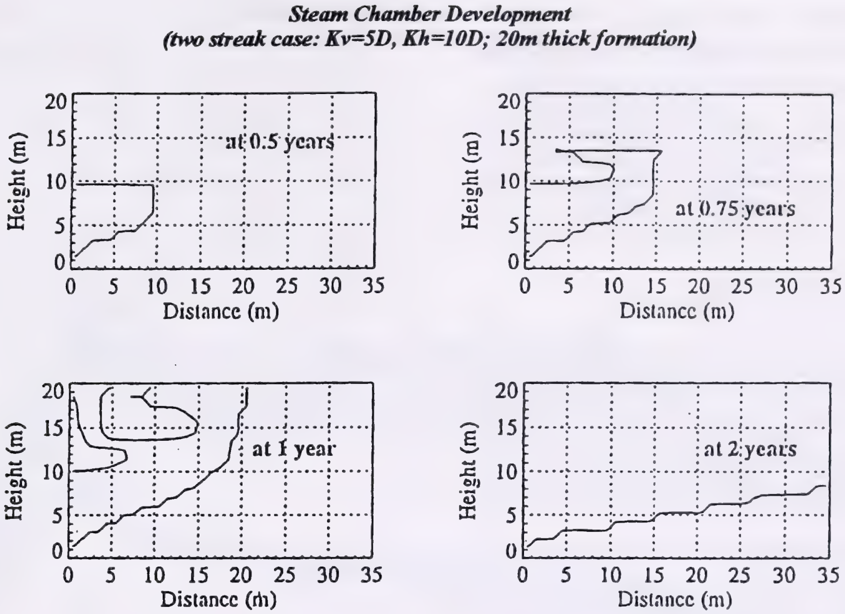


Figure 7.4 — One Tight Streak Case Steam Chambers

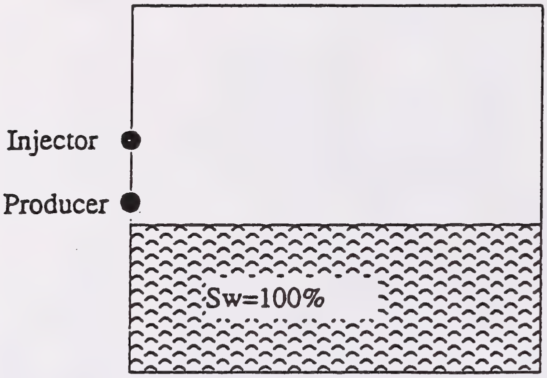


Steam Chamber Development
(two streak case: Kv=5D, Kh=10D; 20m thick formation)

Figure 7.5 — Two Tight Streak Case — Steam Chambers

8) Effects of bottom water layer

A 10 meter bottom water layer (Sw = 100%) was added below the base case formation to investigate its effects.



As the steam chamber grew, some mobilized bitumen went below the producer and was forced into the bottom layer (see Figure 8.2). This caused a slight decline in oil rates (see Figure 8.1). This decline in oil rate was replaced by a corresponding slight increase in water production from the bottom water layer. The steam consumption was similar to that of base case (with no bottom water).

(High permeability 20 m thick formation 2700 kPa, 5 m spacing)	Year	CDOR (m^3/d/ well-pair)	CSOR (m^3/m^3)	Recovery %
base case	2.5	165.42	2.25	72%
10 m bottom water	2.5	141.37	2.76	62%

Under a more practical situation the bottom water layer would likely be water-wet and also with less than 100% water saturation. This would result in much less mobility to water than what was investigated here. Less water mobility should allow less bottom water to be produced, and subsequently, less oil would be forced down into the bottom water layer. Therefore, the effects would be even smaller.

A bottom water layer should not be expected to affect a SAGD process much, provided that the wells follow the designated paths above the water layer.

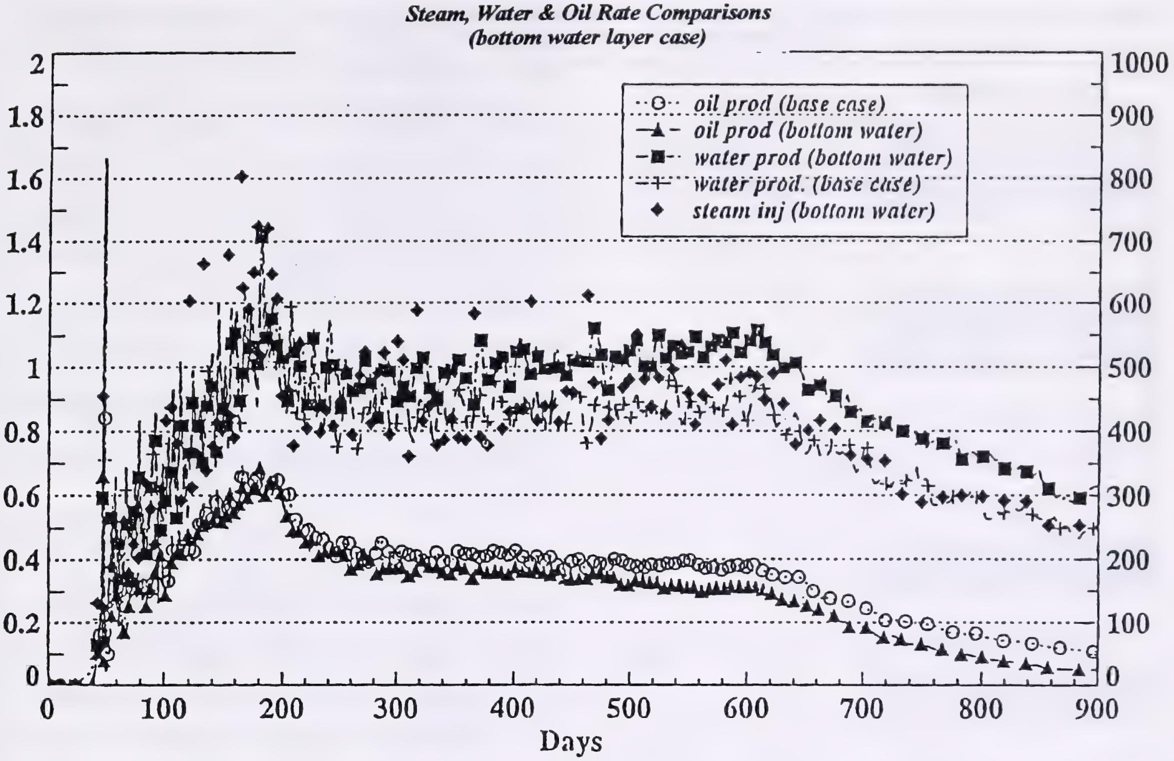


Figure 8.1 — Effects of a Bottom Water Layer

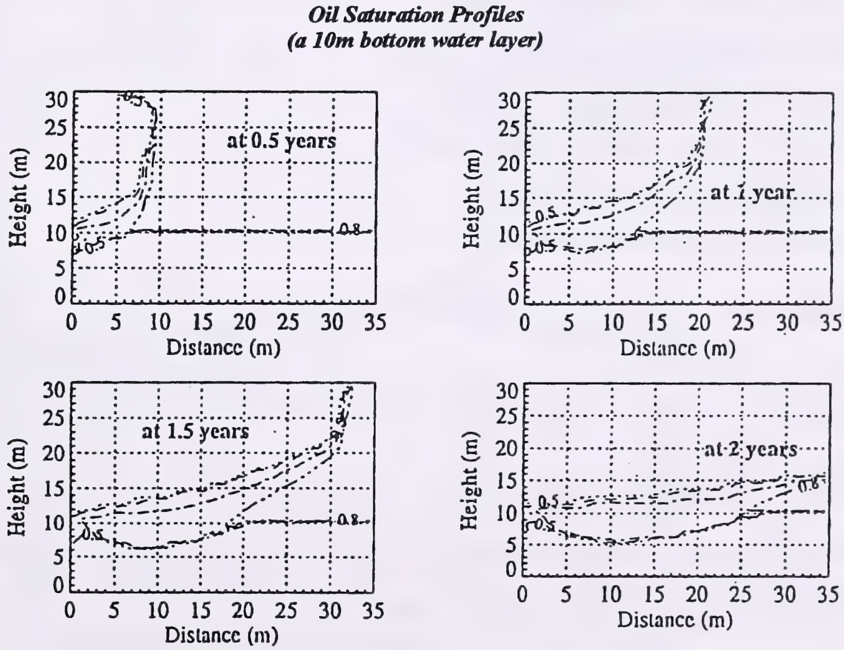
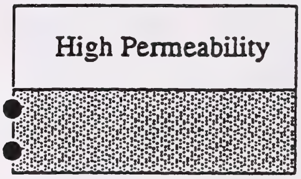
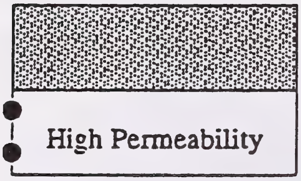


Figure 8.2 — A Bottom Water Case — Oil Saturations

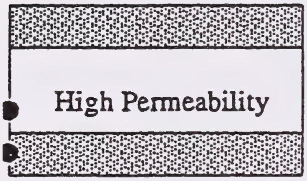
9) Effects of a layered formation



a)



b)



c)

The best oil production (see Figure 9.1) was from case b) where the higher permeability was at the lower layer, and the two wells were also located in this layer. This case was very similar to a typical Athabasca formation where tighter layers were generally at upper zones. A UTF Phase B type oil rate was shown in Figure 9.2 for comparison purposes. Typical UTF Phase B formations contain better permeability lower layer and tighter upper layer. Placing two wells both inside the better quality layer allowed earlier start-up as well as faster steam chamber lateral advancements (see Figure 9.4). The upper layer bitumen drainage also contributed to production; the amount largely depended on the upper layer permeabilities.

(5 m inter-well spacing 2700 kPa 20 m thick formation)	Year	CDOR (m^3/d/ well-pair)	CSOR (m^3/m^3)	Recovery %
base case	2.5	165.42	2.25	72%
case a)	2.5	36.10	3.19	15%
case b)	2.5	148.76	2.29	65%
case c)	2.5	127.50	2.12	56%

The second-best oil production was from case c) where the higher permeability was in the middle layer, in which the injector was located, while the producer was in the tighter layer below. The production rate climbed slowly for the first half year, then reached almost the stable rate of case b). The steam chamber profiles are shown in Figure 9.5.

Case a) produced the least amount of bitumen. It was interesting to note that the better quality upper layer hardly contributed any additional oil production. This was very similar to what was described in Section 2, where the 40 m thick low permeability formation produced the same rate as that of the 20 m thick formation. The production ability of the producer seemed to be controlled largely by the permeabilities of the two wells' immediate surrounding formations. If they were tight, the chamber growth would be very limited, even though permeabilities above the well pair might be good (see Figure 9.3). The steam escaping from the tighter lower zone into the upper better sands quickly condensed, not allowing expected growth of the chamber in this higher permeability layer.

If two wells were both located in the tighter layer, the spacing between the two wells seemed to dictate the oil drainage: larger spacing indicated better oil rate, as in Section 3. However, if there was a higher permeability layer present in the formation, it seemed always advantageous to place both wells in this layer, or at least the injector should be in this higher permeability layer, to allow for reasonable steam chamber growth.

Oil Production Rate Comparisons
(high K: Kv=5D, Kh=10D; low K: Kv=0.5D, Kh=1D)

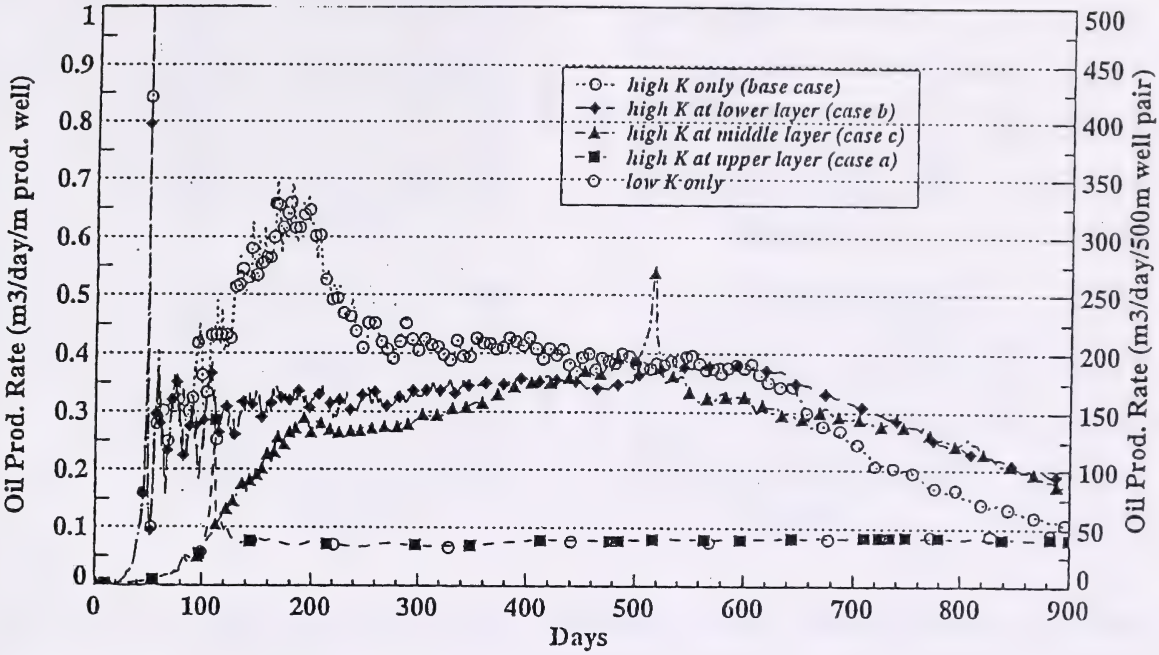
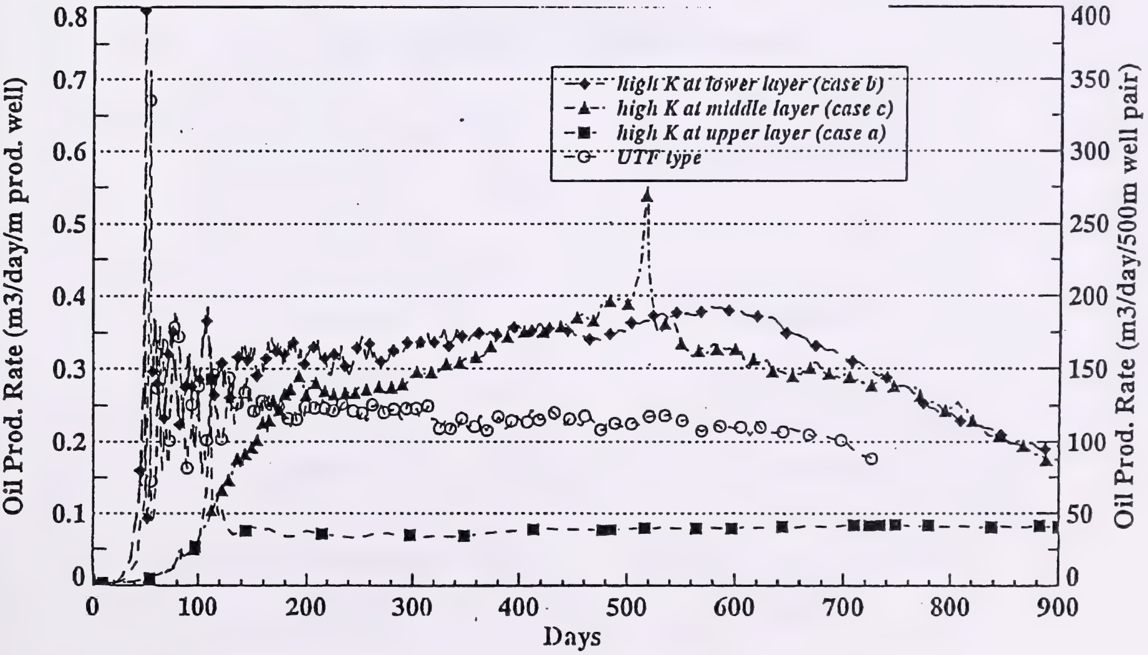


Figure 9.1 — Two Layer Formations — Oil Rates

Oil Production Rate Comparisons
(high K: Kv=5D, Kh=10D; low K: Kv=0.5D, Kh=1D)



UTF type: lower layer use high K, upper layer use Kv=0.15D Kh=0.3D

Figure 9.2 — Two Layer Formations — Compared to UTF Type

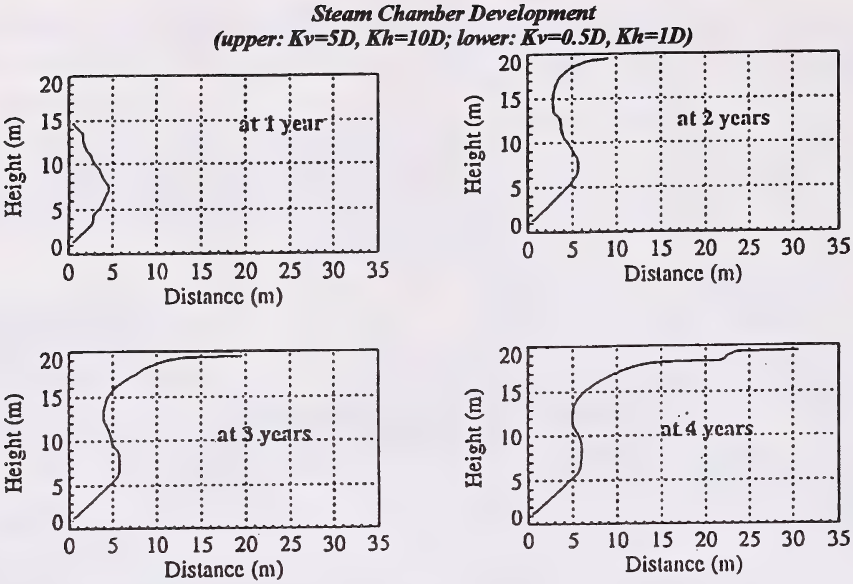


Figure 9.3 — A Layered Formation — High K at Upper Layer

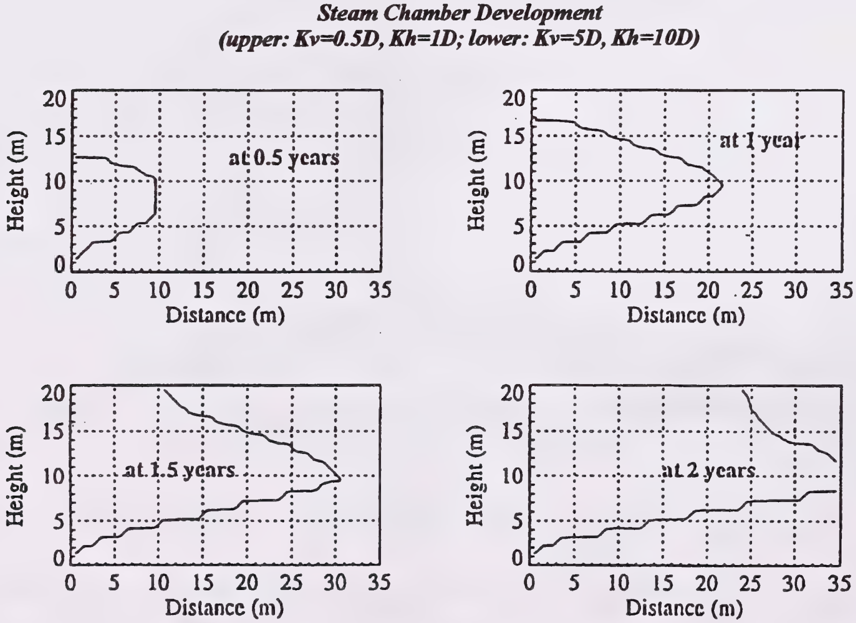
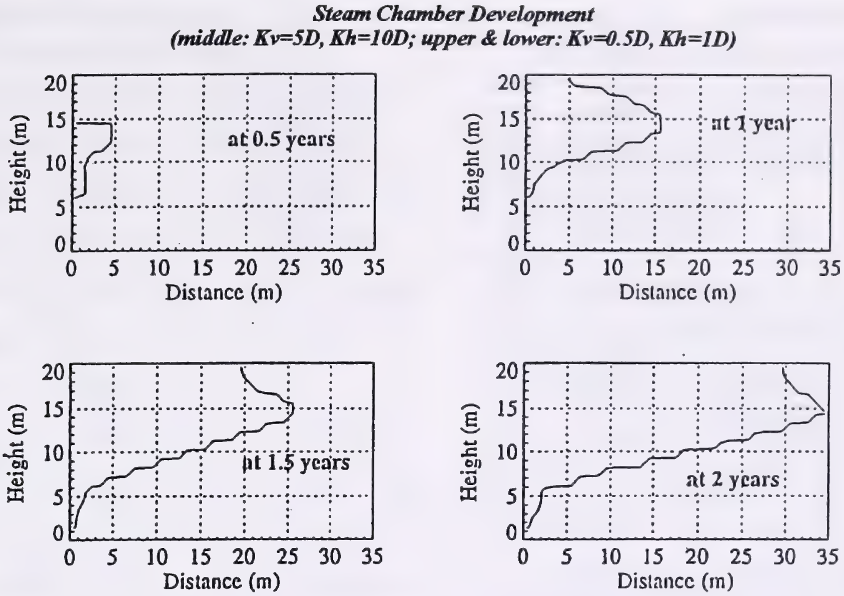


Figure 9.4 — A Layered Formation — High K at Lower Layer



Steam Chamber Development
(middle: Kv=5D, Kh=10D; upper & lower: Kv=0.5D, Kh=1D)

Figure 9.5 — A Layered Formation — High K at Middle Layer

10) Effects of oil viscosities

Two typical oil viscosities, representing Cold Lake heavy oil and Athabasca bitumen, were used for comparison purposes. They produced the following results:

(5 m inter-well spacing 2700 kPa 20 m thick formation)	Year	CDOR (m^3/d/ well-pair)	CSOR (m^3/m^3)	Recovery %
Athabasca Oil	2.5	165.42	2.25	72%
Cold Lake Oil	2.5	172.49	2.29	75%

The observed differences in process performance were quite insignificant (see Figure 10.1), although the relatively lighter Cold Lake type viscosity case did show slight improvement in oil production rates.

At reservoir temperatures, Athabasca bitumen viscosity is around 1,000,000 mPa.s, while the Cold Lake type viscosity is only at 100,000 mPa.s, but the differences become much smaller as they approach steam temperatures (typically around 200° C or higher), about a few centipoise only. Therefore, the viscosity effects were not found to be important on a SAGD process.

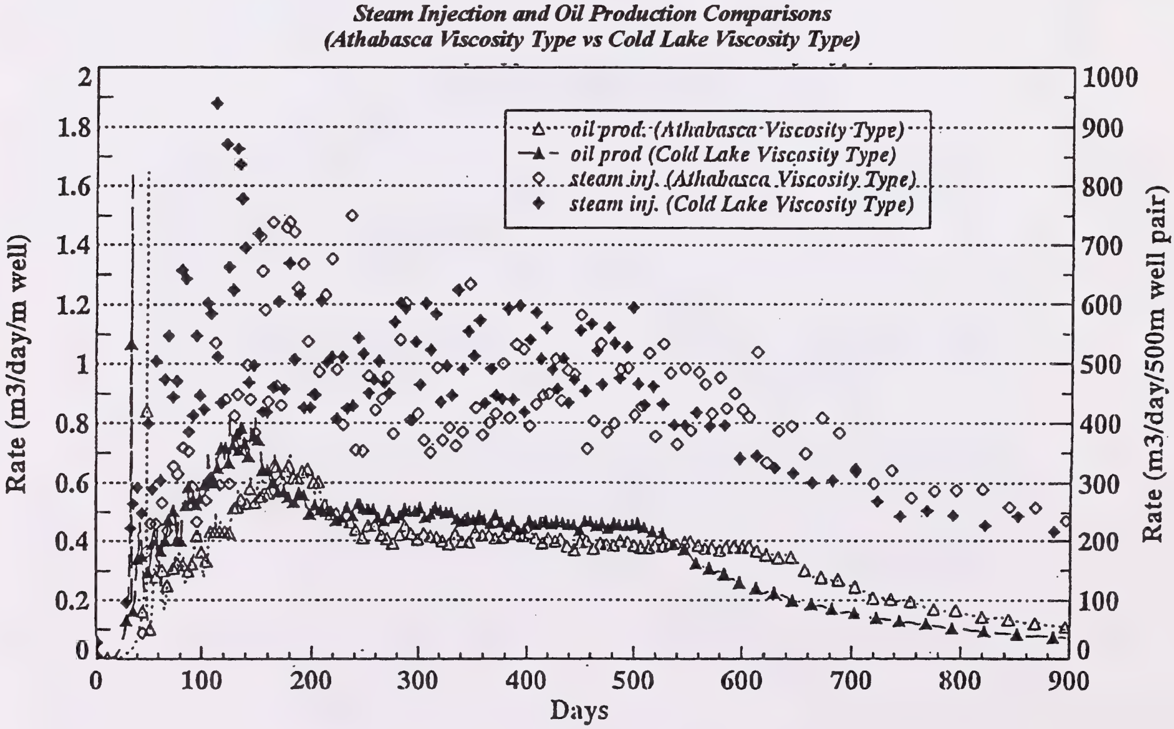


Figure 10.1 — Effects of Viscosities

11) Correlations among peak oil rate, breakthrough, and formation top

Peak oil rate was always achieved when steam chamber interface reached the formation top. This meant that the whole chamber completely touched the formation top. Depending on the areal extent of the contact, the peak rate will vary. When the permeabilities are higher, the size of this contact will also be larger, and so will be the peak oil rate.

However, if the permeabilities are low, the lateral chamber growth will be very limited. The size of the contact will be quite small when the chamber reaches the formation ceiling. Therefore, no sharp increase in oil rate will be observed, as shown in Figure 2.2 in Section 2.

Breakthrough is established when the injected steam reaches the producer. Breakthrough might occur before, at, or after the chamber reaches formation top (peak oil rate). In practice, because of the variation of inter-well spacing along the well pair, plus effect of heterogeneity, different steam chambers will reach the top of the formation at different points and at different times. Thus one peak rate may not be discernible. The UTF (see Figure 9.2) was a special case where breakthrough almost happened at the same time when the peak rate was achieved, while the steam chamber reached the ceiling of the 10 m good quality old sands. The lower quality upper layer had limited effects on the process.

12) Low permeability SAGD enhancement

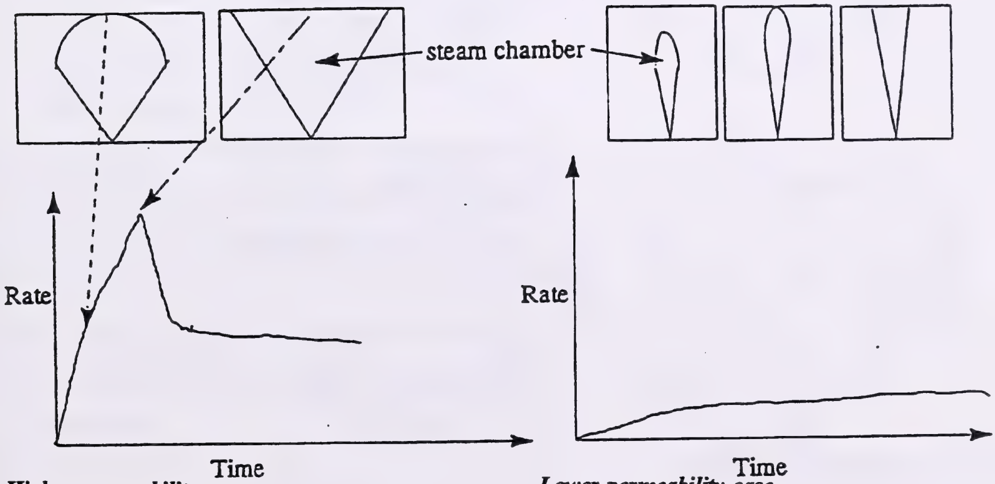
As was discussed earlier, a SAGD process performed quite differently in a low permeability formation. There were a few things that could be done to enhance this performance. Most importantly, injecting at a higher location combined with a higher steam pressure appeared to be a more effective approach.

For a low permeability case, with a thickness of 40 m and permeabilities of Kh = 1 D and Kv = 0.5 D, the increased inter-well spacing from 5 m to 10 m brought up the cumulative daily oil rate at 10 years from 46 m^3/d to 62 m^3/d (see Figure 3.2). Keeping the spacing as of 10 m while using a higher injection pressure of 7000 kPa instead of the base case pressure of 2700 kPa lifted the cumulative daily oil rate at six years to over 99 m^3/d (peak rate up to 125 m^3/d). See Figure 12.1.

(Low permeability 40 m thick formation)	Year	CDOR (m^3/d/	CSOR (m^3/m^3) well-pair)	Recovery %
5 m spacing (2700 kPa)	10.0	46.35	3.13	40%
10 m spacing (2700 kPa)	10.0	62.19	2.50	54%
10 m spacing (7000 kPa)	6.0	99.40	3.46	52%

The steam chamber profile seemed to be a key factor affecting the oil rate. The chamber's lateral growth rate was especially critical. For a low permeability thick formation, using a small inter-well spacing limited severely the chamber's lateral growth, as shown in Figure 2.5. This slow lateral growth was improved by employing a larger inter-well spacing, as shown in Figure 3.3. The improvement was further enhanced by allowing a much higher injection pressure (see steam profiles in Figure 12.2).

Fractures within the low permeability reservoir could also enhance performance. Though this is yet to be tested, the enhancement of vertical permeability with the addition of fractures will enable faster chamber development.



Higher permeability case

Lower permeability case

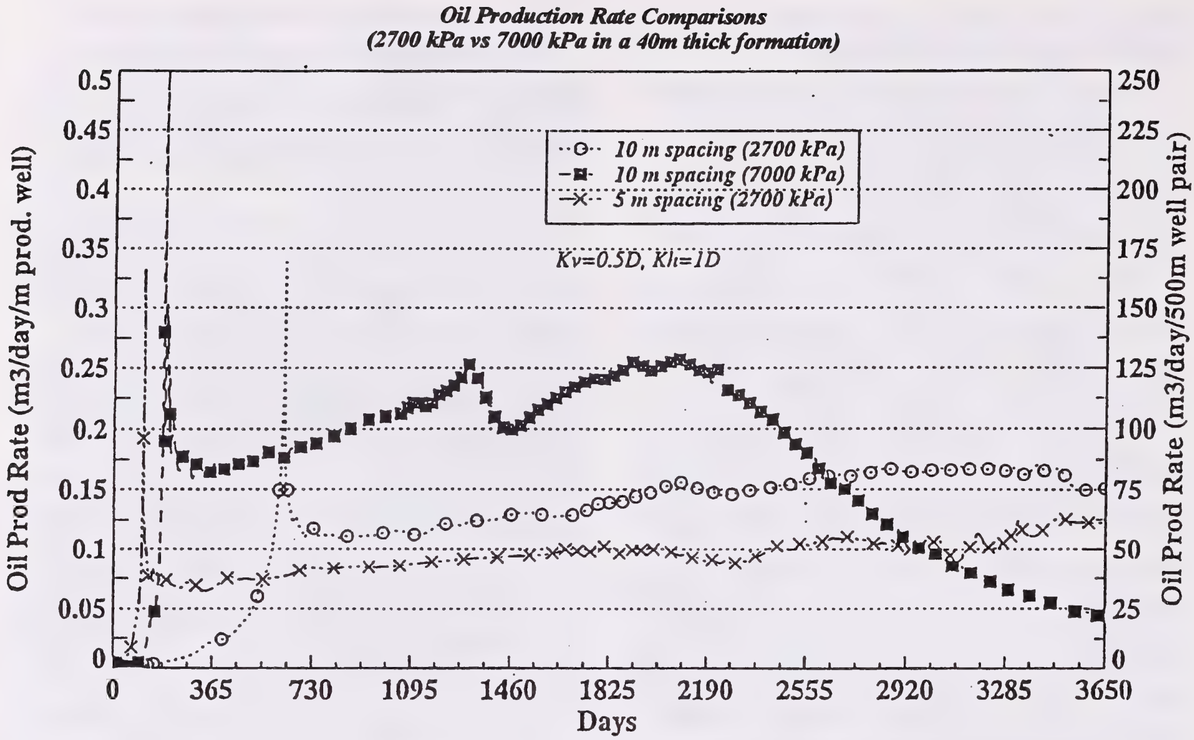


Figure 12.1 — Low Permeability SAGD Enhancement

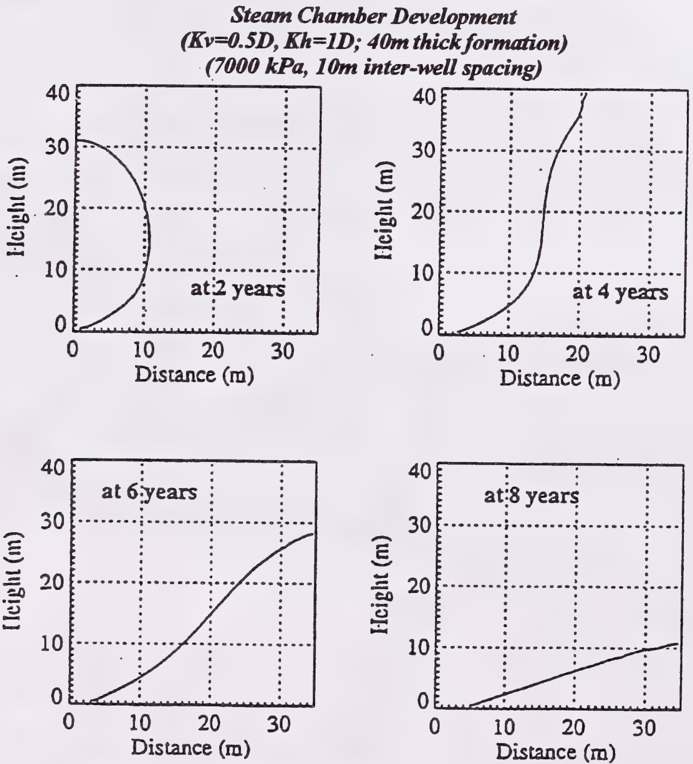


Figure 12.2 — Low K, Larger Spacing and Higher P

Major Conclusions

1) Numerical simulation of gravity drainage problems requires very fine grid block size, such as one metre by one metre, or smaller.
2) For a high permeability reservoir, the oil rates were mainly functions of the gravity drainage height or formation thickness, for instance, a 40-metre thick formation produced almost twice as much as a 20-metre thick formation did. However, for a low permeability reservoir, extra thickness did not generate any higher rates expected.
3) For a high permeability formation, changing inter-well spacing, or the injection location in the reservoir, only affected the start-up time. No advantages were achieved by injecting high in a high permeability formation. For a low permeability formation, however, oil rates benefited significantly by increased inter-well spacing.
4) Vertical permeabilities mainly controlled the oil production rates, but their effects on steam to oil ratios were relatively small.
5) Higher initial water saturation in the formation resulted in higher steam to oil ratios, mainly due to less oil production. Some initial mobile water in the formation accelerated the start-up, but also consumed an excessive amount of steam, due to more water production. This excessive steam injection did not bring up any more oil production.
6) Oil-wet formations were favorable candidates for SAGD processes. This was different from most conventional driving processes, such as a water flood, etc.
7) Some non permeable tight streaks did little damage to the cumulative performance, although they affected some early instantaneous rates. When the steam chamber passed around the streaks, the effects of the streaks were no longer observable.
8) A SAGD process was not expected to be affected much by a bottom water layer, provided that the wells follow the designed paths above the water. An observed slight decline in oil rates was caused by the fact that some mobilized bitumen went below the producer and was forced into the bottom water layer.
9) Among layered formations, when the higher permeability is the lower layer, the process performed the best. Placing both wells in this high permeability lower layer allowed earlier start-up and faster steam chamber growth rates. Well arrangements were extremely critical in a layered formation.
10) Oil viscosity did not play a significant role in SAGD processes. Both lighter heavy oil and more viscous oil sands tended to have very similar behaviors at steam temperatures.
11) Peak oil rate is achieved when steam chamber reaches formation top. The additional amount of the peak rate above its subsequent stable drainage rate depends on the formation permeabilities. In practice, because of the variation of inter-well spacing along the well pair, plus effect of heterogeneity, different steam chambers will reach the top of the formation at different points and at different times. Thus one peak rate may not be discernible.
12) A SAGD process in a low permeability reservoir could be enhanced by injecting at a higher location and at a higher pressure possible. This enhancement relies on the improvement in steam chamber profiles.

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